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September 18, 2017

VIA HAND DELIVERY

Ms. Ingrid Ferrell
Executive Secretary
Public Service Commission of West Virginia
201 Brooks Street
PO Box 812
Charleston, WV 25323

03:55 PM SEP 18 2017 PSC EXEC SEC DIV

Re: Monongahela Power Company and The Potomac Edison Company Petition for Approval of Generation Resource Transaction and Related Relief Case No. 17-0296-E-PC

Dear Ms. Ferrell:

Monongahela Power Company and The Potomac Edison Company hereby file the original and 12 copies of the rebuttal testimony of the following witnesses: Jay A. Ruberto, Robert J. Lee, Thomas Sweet, Kurt P. Leutheuser, Bradley D. Eberts, Dale Evans, and Raymond E. Valdes.

Sincerely,

Gary A. Jack
Senior Corporate Counsel
WV State Bar No. 1855

GAJ:dml

Enclosures

cc: Certificate of Service

03:55 PM SEP 18 2017 PSC EXEC SEC DIV

Re: Monongahela Power Company and The Potomac Edison Company
Petition for Approval of Generation Resource Transaction and Related Relief
Case No. 17-0296-E-PC

CERTIFICATE OF SERVICE

I hereby certify that on this 18th day of September 2017, a copy of the foregoing Rebuttal Testimony was emailed and placed in the U.S. Mail, First Class, to:

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PUBLIC SERVICE COMMISSION
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CHARLESTON

Case No. 17-0296-E-PC

MONONGAHELA POWER COMPANY and
THE POTOMAC EDISON COMPANY

Petition for Approval of a Generation Resource
Transaction and Related Relief

REBUTTAL TESTIMONY OF

JAY A. RUBERTO

September 18, 2017

Q. Please state your name.

A. My name is Jay A. Ruberto. I filed direct testimony on the Companies' behalf.

Q. What is the purpose of your rebuttal testimony?

A. In this testimony, I will address a range of challenges that several intervenors have made to the Companies' application and the Transaction generally. The testimony is organized into sections and covers the topical areas shown here:

- **Section I.** Determination of Capacity Deficiency. I will explain the differences between PJM capacity acquisition obligations and the Companies' recommendation to acquire capacity to protect customers.
- **Section II.** Value of Physical Hedge. I explain in this section that despite other parties' disdain for Mon Power's preference for physical generation ownership, this Commission has recognized the value of a physical hedge against market volatility, as have Staff and WVEUG in this case.
- **Section III.** Allegations of Bias and Undue Advantage. Several parties insist that the same RFP process, which many of them described as essential in the Harrison case, is now a biased, illicit attempt to give AE Supply an undue advantage in Mon Power's capacity procurement. In this section I explain our confidence in Mon Power's legitimate resource preferences and show that amid all their criticisms, no party has identified any specific resource that was unfairly omitted from consideration in the RFP.
- **Section IV.** NPV Calculation Criticisms. My observations in this section largely support Mr. Lee's rebuttal testimony; I confront intervenor criticisms of CRA's NPV analysis of

the conforming RFP bids, including its dispatch model, its forecast inputs and other assumptions, and its ultimate comparison of the three conforming bids.

- **Section V.** Price Criticisms. In Section V, I evaluate intervenor criticisms of the supposed lack of evidence on the appropriateness of the Transaction purchase price. Mr. Lee also addresses a number of these points in his rebuttal.
- **Section VI.** Pleasants – A Solid Asset with Real Value. This section provides a framework for analyzing intervenor criticisms of Pleasants' age, operating characteristics, maintenance, capital needs, and service life, among other topics, and shows that the real reason it prevailed in the RFP was because it offers a far better value than the other conforming bids – even after taking into account reasonable projections for future capital costs.
- **Section VII.** Customer Benefit. Despite some claims to the contrary, the Companies have not asserted that an NPV of $636 million is the yardstick by which the success of the Companies' Application should be measured, much less that it has been a primary justification for transaction approval. Nevertheless, we very much believe that Pleasants offers important benefits in comparison to an extended reliance on market purchases, and that these potential benefits are likely to be very substantial over time.
- **Section VIII.** Preserving Pleasants' Contributions to the State. Pleasants' opponents assign virtually no importance to the preservation of Pleasants' many contributions to the State. Preserving these benefits and promoting the use of West Virginia coal are not only important considerations, but are also among the public interest concerns that the West Virginia Legislature has directed the Commission to consider.

- **Section IX.** Conclusion. I conclude by urging the Commission to assess the Transaction in terms of its potential long-term benefits to customers, determining that the extended low-gas, zero growth landscape that several intervenors have forecasted is simply unrealistic. I will also urge the Commission to weigh all of the Transaction's beneficial attributes in making its public interest determination.

Q. What topics will the Companies' other rebuttal witnesses address?

A. As I've noted, Mr. Lee will address criticisms of the RFP process, administration, scoring, and NPV analysis. Bradley Eberts will address load forecasting issues and Thomas Sweet will testify about the ABB natural gas, energy, and capacity forecasts used in CRA's work and initiatives at PJM, FERC, and the states that may impact prices. Kurt Leutheuser will address opposing testimony on the Black & Veatch assessment of Pleasants as a generating asset, and Dale Evans, Manager, Technical Services at the Pleasants plant, will address a range of Pleasants operational, maintenance, and condition issues. Finally, Ray Valdes will address accounting, rate impact, and temporary surcharge topics, as well as the ill-conceived risk sharing mechanisms proposed by several parties.

Q. Have you attached any exhibits to this testimony?

A. Yes. Exhibit JAR-1 indexes and incorporates various intervenor data responses I will reference in this testimony.[1]

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[1] In this testimony, I will reference data responses included in Exhibit JAR-1 using this format: [Party] DR [#].

Section I. Determination of Capacity Deficiency

Q. How do some of the intervenors mischaracterize Mon Power's showing of a capacity deficiency?

A. Witnesses for Longview, WVSUN/CAG and Sierra Club all insist that the Company has incorrectly calculated its capacity shortfall because, technically speaking, PJM does not require the Companies to evaluate their capacity obligations ***to PJM*** with reference to the winter peak demand. For example, Mr. Schlissel for WVSUN/CAG indicates (p. 11) that the Companies "fail[ed] to follow PJM's methodology" when they projected their future capacity position. He contends (p. 12) that because the Companies have evaluated their capacity position using winter peak load – which he admits is higher than summer peak load within the Companies' service territory – they have "depart[ed] from the PJM methodology" and increased the size of their "purported" capacity shortfall. Other witnesses make similar claims. See Gabel Direct (Longview) at 19–20 (Companies inaccurately calculated a capacity need in a way "inconsistent with PJM's method"); Comings Direct (Sierra Club) at 2–3, 7–8, 10–11 (PJM "financial obligations" imposed on load serving entities are tied to summer peak). By extension, these witnesses also contend that reference to the Companies' winter peak demand thus overstates their capacity obligation. Gabel at 19–20; Schlissel at 10; Comings at 11.

Q. What aspect of this analysis do these witnesses overlook?

A. The witnesses appear to understand the difference between these two types of analyses, but perhaps choose to ignore the difference. For example, Mr. Schlissel describes the difference precisely (p. 9) when he says that "there is a difference between a capacity

need and a capacity *shortfall*" (emphasis original). He implies that a "capacity need" can only be determined with respect to the PJM financial obligation to meet its PJM capacity obligation. Like the Longview and Sierra Club witnesses, Mr. Schlissel effectively takes the position that evaluating a utility's capacity position ***on any basis other*** than PJM's financial requirements is impermissible. At the same time, Mr. Gabel conceded in discovery that there are considerations to take into account in a utility owning capacity in excess of the amount PJM requires (Longview DRs 8 and 11), and Mr. Comings and Mr. Schlissel acknowledged the Commission can authorize ownership of that additional capacity if doing so is reasonable (WVSUN-CAG DR 10; Sierra Club DR 10).

Q. Do you believe from a utility operations standpoint that limiting Mon Power's capacity ownership to the minimum that PJM requires is appropriate?

A. No, I do not. In Section II below, I discuss the Commission's recognition of the value of a physical hedge against market volatility, something that is especially important during the winter peak hours for the Companies. So, I disagree with Mr. Schlissel's contention (p. 9) that generation capacity is not "needed to serve West Virginia customers." Mon Power and PE-WV are winter peaking utilities. The West Virginia IRP legislation directs that utilities focus on their actual peaks, whenever they occur during the year. These witnesses would just have us focus on the summer months because of PJM and its peak in the summer.

Furthermore, Mr. Schlissel apparently questions the idea that there is ***any*** benefit to the Companies owning ***any*** generating capacity at all. He says that "[i]n PJM, a utility is not required to own any generating capacity to meet its capacity obligation – a utility

such as Mon Power satisfies its capacity obligation by paying locational reliability charges to PJM." Simply put, Mr. Schlissel would be satisfied if the Companies owned no physical capacity assets or contractual rights to physical capacity, depending 100% on PJM markets to meet the Companies' PJM capacity obligation and provide service to their customers. Even if Mon Power sought to divest all of its existing generating capacity and depend 100% on markets, Mr. Schlissel might conceivably support that outcome. WVSUN-CAG DR 12. Mr. Comings for Sierra Club has also indicated that although it may be an unlikely scenario, the Companies could do just that, not owning any "steel-in-ground" at all. Sierra Club DR 1.

Q. What is your response to Mr. Schlissel's position?

A. Respectfully, suggesting that the Commission has no interest in utilities' capacity ownership situation other than to meet PJM financial obligations – and that it should not be bothered even by a zero-capacity ownership position – is a flawed and illogical approach that does not reflect real-world needs or, as I'll explain, the Commission's prior statements assessing those needs. His observation (p. 9, n. 21) that the energy and capacity from Pleasants would not be "earmarked" for the Companies' customers does not support his argument at all.

Q. Doesn't Mr. Comings (pp. 11–12) take the position that the Commission itself has recognized in a report that it evaluates Mon Power's supply and demand "during the summer months"?

A. This is a limited observation that only goes so far. Like Mr. Comings' testimony, it purely relates to PJM's financial requirements, and not the need for actual and reserve

capacity based on the Companies' peak load. The Companies' need for actual and reserve capacity is the subject of this proceeding. Pointing at PJM's financial requirements is a smokescreen designed to divert attention from the real issue. It should be rejected for the ruse that it is.

Q. How do you address Mr. Gabel's contention (p. 21) that PJM's Capacity Performance ("CP") construct does not justify Mon Power's 50% reduction in Bath County's assumed capacity value?

A. Mr. Gabel raises this question, not really criticizing the Companies' position as much as implying that it is incorrect. Mon Power's assessment of Bath County's available capacity was not an arbitrary decision; it was based on Section 5.4.1 of the PJM Manual, which specifies availability requirements imposed on CP resources during system emergencies. There are several reasons why assuming Bath County's full, pre-CP availability would put our customers at unnecessary risk.

First, Bath County is a pumped storage facility, and it has only a limited amount of water in its upper pond. This limited supply also limits the number of hours that Bath County can operate at full output to less than 10 hours a day; operation at this level could easily cause the upper reservoir to be depleted at a time when PJM calls for the output, imposing draconian penalties on customers for not having capacity available when called upon. Second, Mon Power is a minority owner in the 3,000 MW facility with only approximately 16% ownership. This limits Mon Power's control over when units pump and generate, so Mon Power must accept the operational determinations of the majority owners. This means that Mon Power has virtually no ability to maintain water in the

upper reservoir at a level adequate to meet PJM requirements and thus preserve a higher capacity value in PJM. Third, because Bath County resides outside the APS Zone, Mon Power cannot use over performance or uncleared capacity from any of its other generation units to protect against non-performance of the Bath County units. Mr. Gabel's assertion is incorrect for all of these reasons.

Q. Mr. Schlissel asserts (p. 13) that in the Harrison case, the Companies based their capacity shortfall projection on their summer peak.

A. Yes, he does – a fact I found interesting for this reason: one of Mr. Schlissel's current clients, WVCAG, also challenged the Companies' presentation of its capacity shortfall in that case, even though the discussion centered on a summer peak-based shortfall.[2] However, it is more appropriate today to base the analysis on winter peaking, because after the Harrison transaction was completed, West Virginia enacted new IRP legislation that explicitly directs utilities to focus on their actual peaks – whenever they occur. For the Companies, that is in the winter. Therefore, I believe our current presentation based on winter peak needs is more responsive to the Legislature's direction and better reflects an appropriate capacity level and reserve margin considering the Companies' winter peaks.

[2] *See* WVCAG's Initial Brief filed on July 9, 2013 in Monongahela Power Company and The Potomac Edison Company, Case Nos. 12-1571-E-PC and 13-1272-E-PW ("Harrison Case"), at 8-10.

Section II Value of Physical Hedge against Market Volatility

Q. How do the intervenors address the value of a physical hedge against market volatility, and how do their positions differ?

A. The intervenors' positions on this issue range from validating this consideration to rejecting it entirely. WVEUG and Staff appear to acknowledge the value of a physical hedge and primarily want it to ensure that adding physical capacity is cost-effective and has minimal associated risks. For example, Mr. Baron for WVEUG (p. 11) differentiates between PJM's responsibility to ensure adequate reliability (met through its capacity requirements for load serving entities) and the price protection that simply meeting PJM capacity requirements does not provide:

> The Pleasants acquisition is really a physical hedge against the PJM market purchases that serve the Companies' customers. It is PJM's responsibility to ensure adequate reliability in the APS zone in which the Companies operate; however, PJM does not provide any price protection to the Companies' customers that would mitigate the impact of higher PJM market capacity and energy prices. This is the role of Mon Power's owned and controlled capacity resources. By selling the output of these resources into the PJM capacity and energy market, and crediting the revenues in the ENEC, the Companies' owned capacity acts a physical hedge to market purchases.

See also Baron at 16–19 (conditions under which Pleasants acquisition would provide beneficial physical hedge). Also, this benefit is implicit in Mr. Eads' testimony for the Staff.

By contrast, Longview and the ESC intervenors (ESC Harrison and ESC Brooke) do not acknowledge this benefit one way or the other, even though each of them would like to be the physical asset supplying it. Ms. Medine does not address this issue for

CAD. As for Sierra Club and WVSUN/CAG, their witnesses not only fail to acknowledge the benefit of physical capacity, but appear to ridicule the entire concept in their direct testimony. As I have noted, Mr. Comings for Sierra Club says (pp. 10–11) that all the Companies are "required" to do is meet PJM capacity requirements, and Mr. Schlissel for WVSUN/CAG contends (pp. 18–19) that there is no evidence that Pleasants will provide any hedge against future wholesale market price volatility.

Q. In the Harrison case, how did the Commission address the issue of protection against market volatility risk?

A. Addressing the need for capacity represented by the Harrison acquisition, the Commission found that the Companies had a capacity deficiency and must rely on the PJM market for both capacity and energy. The Commission then stated that the Companies effectively had an ***obligation*** to remedy this situation. "Failure to deal with the market risk inherent and MP/PE capacity deficit is ***unacceptable***." Harrison Order at 24 (emphasis added).[3] The Commission then acknowledged that the Harrison acquisition would give Mon Power a ratio of installed capacity to load in excess of 100%, but that reserve margins cannot be increased "in a smooth curve when base-load capacity is added"; instead, the Commission recognized that adding base-load units results in a jump in reserve capacity that is gradually reduced over time as internal load grows. "In the meantime, customers receive the benefit of off-system sales that are made from their reserve capacity." Id. Even though the accuracy of load forecasts in the calculation of the capacity shortfall was controverted in the Harrison case, the Commission found that

[3] *See* Commission Order dated October 7, 2013 in Harrison Case ("Harrison Order").

no matter which calculation is more accurate, the capacity deficiency was present and needed to be addressed. Id. at 24–25. The Commission also recognized the importance of addressing potential capacity shortfalls in its order approving the Appalachian Power acquisition of the Amos 3 facility.[4]

Furthermore, as part of the Harrison case, the Companies noted that acquisition of Harrison would only provide enough capacity until 2017. Therefore, it should be no surprise to anyone that Mon Power needs additional capacity, especially in light of the load growth in the territory explained by Dr. Deskins and Mr. Eberts.

Q. Do the Sierra Club, WVSUN/CAG, or Longview witnesses acknowledge these holdings?

A. No, they do not. Again, they appear to believe that the Companies need not own or control any capacity resources at all. As I've noted, this position does not comport with the Commission's expectations for the State's largest electric utilities, which continue to be vertically integrated unlike many other PJM states. So, these parties' opposition to the Pleasants acquisition – and particularly their assessment of the importance of capacity deficits – should be viewed with skepticism. However, in response to discovery, Mr. Comings, Mr. Schlissel, and Mr. Gabel appeared to concede the value of a physical hedge.[5]

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4 See Appalachian Power Company and American Electric Power, Case Nos. 12-1655-E-PC and 11-1775-E-P (Commission Order dated December 13, 2013) at 23.

5 WVSUN-CAG DR 15-16 (Mr. Schlissel agrees in concept with a physical hedge to provide price protection that can mitigate the impact of higher PJM market prices); Sierra Club DR 2 (Mr. Comings acknowledges that using market purchase of capacity to meet a capacity shortfall exposes customers to risk); Longview DR 11 (Mr. Gabel recognizes that Commission should take into account the "energy or

Q. Can you illustrate with an example the value of a physical hedge under certain conditions?

A. In simplest terms, the positive NPV result that CRA calculated for Pleasants is itself evidence of this value. But a simple example may better illustrate it. As Mr. Lee notes in his rebuttal, there are a limited number of hours each year in which having surplus capacity proves to be beneficial. However, during those hours load is high and consequently LMP prices will be near their highest. To illustrate, assume there are 50 hours during which LMP prices in the APS Zone are at $100/MWh, such that customers will see a net benefit of approximately $1 million above Mon Power's variable costs of generation,[6] offsetting Mon Power's higher costs to serve load during those hours.

The value of a physical hedge is that Mon Power has control over these high-load, high-price situations, rather than being at the mercy of the market when they occur. If Mon Power needs to purchase energy from the market during one of these situations to provide for the Companies' customers' needs, it has the benefit of also being able to sell into the market at the same high prices. This allows the revenues generated at the high prices to counter the high costs of supplying customer needs during the same periods. Without the physical hedge that capacity ownership provides, Mon Power must buy the high-priced energy to serve customer load but does not have corresponding revenues from its own market sales during the same periods. This leaves customers exposed – they

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capacity hedge value" that a capacity acquisition proposal may provide).

[6] 50 hours x $100/MWh = $1.25 million, less estimated variable costs of $25/MWh ($300,000), equals $950,000.

end up paying for the difference in ENEC rates. The Sierra Club and WVSUN/CAG witnesses assign no value to this protection in their testimony.

Section III Allegations of Bias and "Undue Influence"

Q. In the Harrison Transaction, what did the Companies learn about several of the intervenors' views on the value of an RFP to acquire capacity resources?

A. We learned from that case that Staff, CAD, WVCAG, Sierra Club, and WVEUG believed that an RFP should have been used in that case, both to identify the lowest cost resources to meet a capacity shortfall ***and*** to ascertain the fair market price of those resources. For example, the CAD's then director, Byron Harris, recommended that the Commission order the Companies issue an RFP in order to determine the most cost-effective means of meeting their customers' future electricity needs. "An RFP process will allow the Commission to review multiple alternatives … and is the only way that the Commission can determine the costs and benefits of all of the options available to serve the Companies' customers." Harris direct testimony (admitted as CAD Ex. BLH-D at May 31, 2013 hearing) at 3–4.

In fact, Mr. Harris devoted an entire section of direct testimony (pp. 24–29) to the merits of RFPs, both in terms of identifying resources and establishing a price for them. A RFP would help insure that terms of a proposed transaction would be reasonable because they would be set by market forces, and would also likely ensure that no undue advantage would arise. The benefits of an RFP for these purposes was a theme common

to all of these parties' testimony and briefing, and some even asserted that the lack of an RFP to establish the Harrison price was a fatal flaw.[7]

Q. In light of those positions, are the same parties' current positions frustrating to you?

A. Yes. This is especially so since many of the same parties, in filings made in and after the 2015 IRP, still were demanding that Mon Power issue an RFP. In fact, the CAD and Staff jointly petitioned for a "show cause" order in August 2016, urging the Commission to direct the Companies to explain why they should not be required to use an RFP process if they chose to acquire new capacity.[8] Despite the earlier clamor for an RFP because of the many attributes it would provide, these intervenor witnesses say nothing about those same attributes in their written testimony in this case.

Nevertheless, Mr. Schlissel, Mr. Comings, and Ms. Medine still agree that the use of a competitive RFP process:

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[7] See the following post-hearing briefs from the Harrison Case: CAD Initial Brief dated July 9, 2013 at 7, 30 (stating that the Transaction Price does not reflect a reasonable market price "as demonstrated through a RFP"); Sierra Club Initial Brief dated July 9, 2013 at 5 (asserting that submission of a RFP would "determine the least-cost resource . . . available"); Sierra Club Reply Brief dated July 19, 2013 at 4 (asserting that the "true purpose" of a RFP is to protect ratepayers by soliciting least-cost resources); Staff Initial Brief dated July 9, 2013 at 5 ("The lack of a RFP specifically leaves a gaping hole in the side of the Companies' analysis."); WVCAG Reply Brief dated July 19, 2013 at 4 ("The purpose of an RFP would be to see what other resources are available that might be able to meet the Companies' shortfall at a lower price . . . .").

[8] *See* the following filings in the "show cause" docket, Case No. 16-1074-E-P: Staff/CAD Petition dated August 5, 2016 at 3 (citing Mr. Harris's support for the "dynamics of the open market" as expressed in the Harrison Case, Staff and CAD contend that an RFP could "allow the competitive process to offer a variety of generation resources to meet customers' needs"); Staff Reply to Motion to Dismiss at 5 ("any reasoned procurement of capacity would, at the very least, have an RFP"); WVSUN/CAG Petition to Intervene dated August 18, 2016 at 3 (WVCAG seeks to ensure that Companies seek cost-effective resources through a competitive RFP); WVSUN/CAG Response to Motion to Dismiss at 9 ("An RFP is . . . a critical tool to ensure that utility service is economical and customer charges are just and reasonable."); WVEUG Petition to Intervene dated September 7, 2016 at 3 (Mon Power must "test the market" through an RFP "prior to deciding to acquire a fixed capacity asset").

- is a reasonable means for a load serving entity to identify the most cost-effective source of energy or capacity or both;
- is helpful in demonstrating what options are available in the market;
- allows a regulator to determine the costs and benefits of available options;
- is helpful in establishing the reasonableness of a transaction proposed to be consummated based on the RFP result;
- is helpful in establishing the market value of the asset to be acquired;
- is helpful in establishing that the value of the asset (as determined by the prevailing bid) is reasonable; and
- is helpful to ensure that no undue advantage is afforded to RFP participants, including affiliates of the RFP issuer.

See WVSUN-CAG DRs 6 and 7, Sierra Club DR 20, and CAD DR 18. In other words, they believe RFPs in general are valuable and provide many benefits – just not ***this*** RFP.

Q. In your view, does the RFP in this case have those same beneficial attributes?

A. Yes – we developed the process so that all potential suppliers, including affiliate interests, would not be advantaged or prejudiced and so the purchase price of any resulting transaction would be a presumptively reasonable, market-derived price. For Mon Power, the most important step in this process was to select an independent expert to structure and administer the RFP. Mon Power first interviewed multiple candidates for the role of RFP developer and administrator. Based on CRA's expertise in developing and administering competitive solicitation processes, Mon Power then retained CRA for this purpose. Mon Power then directed CRA to design a RFP that met all standards for fairness and insured no preference to anyone. Other than specifying the types of

resources Mon Power preferred and the preferred locations for them, Mon Power allowed CRA to design the RFP, administer the RFP process, and evaluate the responsive bids. CRA contacted 28 different resources (20 existing assets and eight projects under development) to provide them with advance notice that the RFP was coming and invite them to participate. Importantly, in its evaluation of all of the conforming bids, CRA utilized the same NPV analysis, incorporating the same independent assumptions on load growth and market prices. All of these efforts were expected to enable a neutral evaluation of all responsive bids, whether or not an affiliate was involved. Mr. Lee's direct testimony shows the approaches CRA used to ensure this neutrality. And, we are confident that Mr. Lee's experience and expertise in this area far exceeds that of intervenor witnesses who have criticized his approach.[9]

From my perspective, undertaking an independent RFP process like this one was exactly what the Harrison intervenors said they wanted. Now that Mon Power has done exactly what the Harrison parties wanted it to do, we face strident allegations that the entire process was rigged and the resulting price is not fair. Obviously, these challenges are very disappointing; it is as if all of the beneficial aspects of an RFP that these parties extolled in Harrison have vanished. It truly seems that there is no way to appease these parties and that the positions they take are outcome oriented instead of being rooted in principle.

[9] Mr. Schlissel, Mr. Comings, and Ms. Medine have never participated in the design, development, administration, or scoring of an RFP for capacity resources. WVSUN-CAG DR 23; Sierra Club DR 26; CAD DR 57.

Q. Are you confident that the RFP design, process, administration, and scoring were fair and worked as intended?

A. Yes, we are confident of these things. Mr. Lee's rebuttal addresses these points in more detail. We are also confident in the legitimacy and justification for our resource preferences, which arise from real-world concerns that face the Companies – including the avoidance of PJM penalties that customers might be required to pay if these preferences were not respected.

Q. How do you respond to criticisms in these areas?

A. In my view, no intervenor has effectively undermined Mon Power's legitimate preferences for the physical asset over a PPA and for an asset located in the APS zone. I will address each of these in turn.

Preference for Physical Asset over PPAs

Q. Do Mr. Dorn's comments (pp. 5-6) regarding how a PPA can be structured undermine the value of physical assets?

A. No. As I described in my direct testimony (p. 11), there are many reasons why owning a physical asset is preferred. Mr. Dorn makes many statements about how a PPA "could" be structured in an attempt to improve the value of a PPA to Mon Power. However, it fails to mention how any of these contractual arrangements impact the cost, obligations, or risks to Mon Power. For example, on page 6, lines 3-6, Mr. Dorn floats the idea that a PPA could be structured to allow off system sales when economic. However, he does not discuss the cost of such an option, for example, nor does he mention any obligations Mon Power to continue to purchase any output even when uneconomic. Mr. Dorn continues to

tout the ability of Mon Power to negotiate O&M and capital up front, but all of these would come at a cost to Mon Power where it is left with the cost for improvements made to a plant it does not own, and would not have rights to once the PPA expires. Moreover, because all of these commitments would be contractual, there is risk of non-performance by the supplier if at some point in the future the PPA terms become unfavorable to the generator making them unable to continue operations. Fortunately, there has been a real-world check on Mr. Dorn's theories; while non-conforming, Mon Power did receive bids for PPAs, and they provided a significantly lower NPV as determined by CRA.

Q. Have other intervenor witnesses conceded that there can be advantages to owning a physical resource?

A. Yes – both Mr. Comings and Mr. Schlissel concede owning a physical asset can have advantages over a generic PPA. Sierra Club DR 22, WVSUN-CAG DR 21. Ms. Medine said that "[t]here may be legitimate reasons," but she was unable or unwilling to identify what they might be. CAD DR 24.

Preference for Asset in APS Zone

Q. Why did Mon Power decide to limit the RFP to assets located in the Allegheny Power System ("APS") zone?

A. Mon Power decided to limit the RFP to the APS zone, unless there were fewer than three bids received, as a means of mitigating the CP penalty risk I addressed in Section I above, as well as in my direct testimony. Resource performance during Performance Assessment Hours can effectively be netted from a performance risk management standpoint due to the ability under PJM's rules to retroactively replace capacity resources

during such hours. Specifically, PJM's rules allow for the "over-performance" of one resource to offset the "under-performance" of another resource if certain criteria are met. One of those criteria is that the replacement resource must be located in the same Locational Deliverability Area ("LDA") (or a more constrained child LDA) as the resource being replaced. The replacing and replaced resources also must be subject to the same Performance Assessment Hour(s). Acquiring a resource located in the same zone as most of Mon Power's existing fleet—the APS zone—allows the company to mitigate its CP penalty exposure effectively through this replacement capacity mechanism. None of the intervenor witnesses controverted this assessment.

Additionally, the Companies obviously have an interest in locating their generation resources not only within the APS zone, but within their own service territory to provide ease of delivery, coordination, and economic benefits to the service territory.

Q. Are CP penalties only applicable if PJM classifies the APS Zone as a constrained LDA as Ms. Medine suggests?

A. No. She ignores the clear language of the PJM Manual provision regarding replacement capacity, and fails to tie the manual provision in with other relevant provisions in the PJM governing documents. First, Section 8.9 of PJM Manual 18 details the five requirements for a replacement capacity resource:

> [U]pon a request to PJM made no later than three business days after a Delivery Day containing a Performance Assessment Hour, Replacement Capacity Transactions may be permitted retroactively effective with the Delivery Day provided such transaction meets the following criteria: (1) the replacement

> resource must have already been in the same sub-account as the resource being replaced on the Delivery Day, (2) the replacement resource must have been included in the same Performance Assessment Hours as the resource being replaced, (3) the replacement resource must have the same or better temporal availability characteristics as the resource being replaced, (4) the replacement resource must be located in the same LDA (or a more constrained child LDA) as the resource being replaced, and (5) the resulting total Daily Resource Commitments (RPM and FRR) (in UCAP terms) on a generation resource used as a replacement resource cannot exceed such replacement resource's Actual Performance during the Performance Assessment Hours.[10]

CAD has alleged elsewhere that Mon Power is somehow misapplying the fourth requirement, which states that "the replacement resource must be located in the same LDA (or a more constrained child LDA) as the resource being replaced." However, a comprehensive list of PJM LDAs is found in Schedule 10.1 of the Reliability Assurance Agreement ("RAA"). The APS zone is included in that list as a PJM LDA "for the purposes of determining locational capacity obligations."[11] So any suggestion that the APS zone is not an LDA is incorrect. The fact that the APS zone has not been constrained in recent capacity auctions is not the relevant inquiry as to whether capacity will meet the replacement capacity criteria pursuant to Section 8.9 of PJM Manual 18.

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[10] PJM Manual 18 § 8.9.

[11] PJM RAA, Schedule 10.1(A)

Second, and perhaps even more importantly, you cannot ignore the second requirement of Section 8.9r, which states that "the replacement resource must have been subject to the same Performance Assessment Hour(s) as the resource being replaced." This provision is important because PJM has the authority to declare a Performance Assessment Hour at the region-wide level as well as at the zonal or sub-zonal level. PJM is not restricted to declaring a Performance Assessment Hour in the zones defined by the clearing process in the PJM capacity auction. In other words, PJM does not have to determine that there are constraints that merit the creation of a new LDA for a capacity auction in order to declare a Performance Assessment Hour in a zone or sub-zone. FERC has made this point very clear, noting in its CP rehearing order that Performance Assessment Hours can occur "in any locational boundary as large as the PJM region and as small as a subset of a control area."[12] Thus, when a Performance Assessment Hour occurs in the APS zone, a resource located outside the APS zone but within the Rest-of-RTO zone will not qualify to serve as a replacement capacity resource.

Q. Has PJM provided any clarification regarding the "same Performance Assessment Hour" requirement within the replacement capacity rule?

A. Yes. As part of the CP development 1 and implementation process, PJM maintained a "FAQ" document that responded to stakeholder questions regarding the CP construct. On November 30, 2015, PJM posted a response concerning eligibility to serve as a retroactive capacity replacement. PJM responded that to qualify as a replacement

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[12] PJM Interconnection, L.L.C., 155 FERC ¶ 61,157, at P 135 (2016).

capacity resource, a resource has to "be within the portion of the LDA subject to nonperformance charges."[13]

Q. What is your response to allegations that Mon Power's APS zonal requirement is based on a hypothetical concern that the APS Zone could be constrained in future capacity auctions?

A. This allegation is without merit and ignores the relevant question. The implicit assumption behind this statement is that the zones modeled in the capacity market auctions are the relevant zones for purposes of retroactive capacity replacement. Ms. Medine's position conflates constraints in the capacity auction clearing process with the manner in which Performance Assessment Hours are declared and CP penalties are assessed. Mon Power appropriately considered the risk that Performance Assessment Hours can occur in a more localized area than the Rest-of-RTO zone, including even a subset of a control area. Indeed, an analysis performed by PJM analyzing historical events that, under today's CP rules, would have constituted Performance Assessment Hours, supports Mon Power's decision. The analysis reveals that on several occasions between 2005 and 2015, in the past Performance Assessment Hours would have occurred in the APS 1 zone (but not the full Rest-of-RTO zone) on several occasions.[14] No one

[13] Capacity Performance FAQs (July 31, 2015), https://urldefense.proofpoint.com/v2/url?u=http-3A__www.pjm.com_-2D_media_committees-2Dgroups_committees_elc_postings_capacity-2Dperformance-2Dfaqs-2D7-2D31-2D15.ashx-3Fla-3Den&d=DwMFAg&c=YOHA32qHoO0MIaoXxJhqDw&r=sqFbRDaABGHSoTqwHL_v7v737PA7PFK1LCU9tXhpegE&m=6LhR9jj6cduytGuwJZ_pQtwbJ2KZbuSRlFMkCVQY22A&s=qdKu7XowWrRmPFhWvUsJ1aGbOTSThNwp-nELuxTXNcs&e= (emphasis added).

[14] Historical Emergency Procedures Triggering Performance Assessment Hours, http://www.pjm.com/~/media/committees-groups/committees/elc/postings/historical-performance-

has explained how this is an inappropriate way to manage this risk on a going forward basis. Further, no one has offered an alternative means for managing this risk in the absence of acquiring a resource in the APS zone.

Q. Are there any additional reasons that Mon Power would prefer capacity located in the APS zone?

A. Yes. I note more generally that acquiring a resource in the APS zone provides a valuable hedge separate and apart from the "replacement capacity" mechanism. In addition to assessing penalties to resources that underperform during Penalty Assessment Hours, PJM's rules provide resources that over-perform during such hours the opportunity to earn bonus payments.[15] If a Penalty Assessment Hour event occurs in the APS zone, the risk that one unit may underperform can be hedged to some extent by having other units with the ability to over-perform and collect bonus payments.[16]

Q. Have any intervenor witnesses acknowledged that that there can be legitimate bases for preferring capacity located in the APS Zone?

A. Yes. Mr. Schlissel indicated that although he is aware of the rationales for this preference I presented in my direct testimony, his testimony did not focus on this issue, and therefore he cannot opine on it. WVSUN-CAG DR 22. Similarly, Mr. Comings acknowledged that "there may be certain advantages to owning a generic asset in the APS

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assessmenthours.ashx.

[15] See PJM OATT, Att. DD, § 10A.

[16] Due to the manner in which bonus payments are calculated, bonus payments are unlikely to offset penalties on a 1:1 basis; however, the bonus payments can nevertheless be considered a valuable hedge against CP penalty risk.

Zone," but that he did not evaluate any such advantages (or disadvantages). Sierra Club DR 23. Ms. Medine ducked this question entirely: "It is not CAD's job to provide a justification. CAD's position is that if there were justifiable reasons for the APS Zone limitation, Mon Power did not provide them." CAD DR 25.

Allegations of "Bias" and "Undue Influence"

Q. How do you respond to intervenor allegations of actual bias creating an "undue advantage" to AE Supply?

A. I think those allegations are completely unsubstantiated and entirely false. No party has shown how AE Supply was given an undue advantage in the bidding process over others, or explained how it used that supposed undue advantage to become the winning bidder in the RFP. In fact, as I read the testimony, only one witness (Ms. Medine for CAD) even asserts (p. 5) that AE Supply actually gained an undue advantage over actual or potential RFP respondents, and she provides no concrete evidence to support that claim. No party has asserted that AE Supply benefited from any knowledge that it acquired as a result of its affiliate status that helped it prevail in the RFP; nor could they, since it simply is not true. Moreover, these parties fail to acknowledge that if AE Supply really had an undue advantage, then it presumably could have submitted a bid much closer to those of the other potential bidders than turned out to be the case, in order to narrow the gap between the Pleasants offer price and the offers made by other bidders.

Q. How did Mr. Comings and Ms. Medine substantiate their claims of bias and undue advantage in response to discovery?

A. Not surprisingly, they were unable to do so, although their respective discovery responses evidenced dramatically different positions on their inability to substantiate claims of bias and undue advantage. Mr. Comings for Sierra Club did not identify any facts serving to prove the exercise of deliberate bias in favor of AE Supply, saying he had not offered an opinion on this point. Sierra Club DR 17. He also said that the selection of Pleasants in the RFP process was not evidence of bias in and of itself. Sierra Club DR 18. On the other hand, Ms. Medine for CAD doubled down on her position, contending that her observation that the transaction is "extremely advantageous to FE compared to the likely alternatives" is, in and of itself, sufficient to prove the exercise of bias in both Mon Power's RFP requirements and CRA's design, administration, and scoring of the RFP.[17] When asked what support she had for this position, she offered nothing other than her written testimony. CAD DR 12. She also thinks that her unsupported assessment of these issues is a sufficient basis for the Commission to conclude that the transaction will be unfair to the Companies' customers. CAD DR 13.

Neither of these witnesses acknowledges that no one came close to Pleasants in the NPV analysis performed by CRA. The NPV gap was caused primarily by the low bid per kW of generation offered by AE Supply. In summary, I find no evidence in the

[17] Similarly, Ms. Medine believes that the mere fact that FirstEnergy's strategic initiative to exit the competitive generation business is likewise "evidence of bias" in Mon Power's RFP requirements and CRA's design, administration, and scoring of the RFP. Again, she offered no support for this conclusion other than her written testimony. CAD DR 6. Somewhat inconsistently, she denied that the fact that AE Supply had the winning bid in the RFP was evidence of the exercise of bias, although she believes it still is "evidence the Commission should consider." CAD DR 8.

intervenor testimony, or in the bidding results, that the RFP process and its results were anything other than fair and reasonable under the circumstances – much less that they resulted from the exercise of bias, deliberate or otherwise.

Q. Amid the intervenors' criticisms of the RFP process, has any of them identified specific resources that the RFP process overlooked?

A. No. No party has shown that the RFP characteristics resulted in any specific resource – existing or planned, and inside or outside of the APS zone – that (i) missed out on the RFP response because of response times or the holiday season; (ii) was overlooked in the RFP process or administration of it; (iii) would have bid (much less bid successfully) if the RFP terms or design had been different; or (iv) could have met the capacity need. There is simply no evidence in any of these areas, making the criticisms more speculation than anything else – an assessment borne out in discovery.[18]

[18] *See* CAD DR 20, Sierra Club DR 24 (Ms. Medine and Mr. Comings unable to identify any potential RFP respondent that was discouraged, deterred, or prevented from qualifying to bid or submitting a responsible bid due to the timing of the process); WVSUN-CAG DR 17 (Mr. Schlissel could not identify assets outside of APS Zone that could provide capacity on a more cost-effective basis than Pleasants at $150/kW).

Section IV NPV Calculation Criticisms

Q. Mr. Lee's rebuttal addresses CRA's NPV analysis. Do you have any additional thoughts about intervenor criticisms in this area?

A. Yes. As an initial matter, I agree entirely with Mr. Lee that the purpose of the NPV analysis was to evaluate and compare the RFP conforming bids using consistent market assumptions. Mr. Lee shows that many of the intervenor criticisms of the NPV analysis relate to input assumptions that were uniform across the bids considered, or ones for which similar criticisms and proposed modifications might be made to the other responsive bidders. There is no question in my mind that the NPV comparison that CRA undertook accurately ranked the conforming bids in terms of value, and that the difference in value among the conforming bids is reasonably represented.

Q. Let's talk first about the assumptions that informed the NPV analysis. Could you identify these and explain how they would apply to all conforming bids?

A. These factors relate to future market forecasts such as natural gas prices, capacity prices, energy prices, and load forecasts. Intervenor claims that these forecasts were too high do nothing to impair CRA's ranking of the conforming bids. Likewise, if the CRA's NPV approach had been to conduct the numerous sensitivity analyses and additional scenarios that certain intervenors recommend, those additional analyses would have had to be applied to all of the conforming bids, not just AE Supply's. If this had been done, the relative positions of the conforming bids would not have changed.

Q. What about claims that the historical experience of Pleasants undercuts some assumptions used in (or produced by) CRA's application of its dispatch model?

A. As Mr. Lee explains, CRA's work was not designed to identify what each conforming bid's actual performance in PJM markets only with reference to historical information about those respective facilities. To do this would have resulted in inconsistent assumptions as between the NPV analyses, such that the outcomes might not have been fairly compared. Obviously, this approach would have been at cross-purposes with CRA's NPV analysis, and the comparative results would have been less reliable and even subject to challenge.

Q. How do you respond to Mr. Gabel's criticism (pp. 29–31) that the 15-year forecast period is too short?

A. I simply disagree with this assessment, along with the suggestion that the 20-year forecast period used in the 2015 IRP must have been the same as the assessment period CRA used. In my view, 15 years is an appropriate period to assess the relative values of RFP bids on a fair basis, and extending the period beyond 15 years would have little incremental impact on the relative scores, because the variables at that time (in addition to being more uncertain) are farther away and have less impact on the NPV analysis.

Q. Ms. Medine criticizes the NPV analysis for not considering the difference in megawatts as between Pleasants and Longview. Do you think this difference is material in the context of the RFP?

A. No, I do not. I simply do not understand Ms. Medine's suggestion (pp. 52–53) that the NPV analysis should have varied as between these two conforming bids because one

provided more capacity than the other. The NPV analysis was done on a per kW unit basis in order to compare units of different sizes on an applies-to-apples basis, so the capacity size of the resource does not affect the economics.

Q. Do you believe that the NPV analysis should have reflected a closure of Pleasants in year 20 after the start of the analysis?

A. No. Other than speculation, I have seen no evidence to suggest that Pleasants will close in that year just as none of the stakeholders have suggested that Fort Martin is nearing the end of its useful life (its units being approximately 12 years older than those at Pleasants). Nor do I see any fair way to identify what the timing of Pleasants closing costs would be, to quantify the associated costs, or to determine the need for or amount of capacity replacement to take Pleasants' place. More importantly, assuming these additional costs for Pleasants but not for other conforming bids would result in those bids not being impaired by the same layer of cost. The witnesses taking this position (Medine, pp. 10, 53; Baron, pp. 25–26; Comings, p. 6) offer no support for their closure assumptions, nor any agreement of what closure costs might be or the cost to acquire replacement capacity.

Q. Many of these witnesses contend that compliance costs for the Effluent Limitation Guidelines ("ELG") and the McElroy's Run impoundment closure should have been included in the NPV analysis. Do you agree?

A. I defer to Mr. Lee on the appropriateness of such considerations in an NPV calculation, and to Mr. Evans on the actual needs at Pleasants. But in both cases, the occurrence of these costs, the timing of that occurrence, and the amount of costs at that time are all very uncertain.

Q. How do you respond to Ms. Medine's assessment (p. 33) that the coal contract she identifies is "above market"?

A. I disagree. Ms. Medine does not acknowledge that this contract is for 2 million tons a year, and at the FE-Allegheny merger the allocation was split between Mon Power and AE Supply, with both having the same price and terms. Moreover, while the current cost per ton is currently slightly above current spot market, this has not always been the case, and there is no assurance it will be the case between now and the expiration of the contract at the end of 2020.

It is also worth observing that if Mon Power is permitted to acquire Pleasants, it will use the same fuel purchasing philosophies and approaches to procure least-cost fuel supplies as it does for Harrison and Fort Martin. From time to time, those facilities have had multi-year coal contracts that, due to changes in the market over time, may become "above" or "below" market, too; in these instances, the Commission does not penalize the Companies in ENEC cases if the fuel procurement decisions were reasonable at the time they were made and Mon Power has taken appropriate steps to minimize the extent and duration of adverse pricing situations. Finally, the subject coal contract's price is right where the ABB price forecast for coal is predicted, so the Companies believe that the coal contract is at market for long-term coal supply.

Q. Ms. Medine has taken the position that items she contends were missing from the contract summary for this coal contract (Medine, p. 31) both impaired Mon Power's consideration of AE Supply's offer for Pleasants and misled Mon Power and CRA (CAD DR 31). Are these allegations accurate?

A. Not in the least; nor do I agree with her claim that this supposedly "missing" information should have "invalidated or disqualified AE Supply's offer" for Pleasants (CAD DR 31). Mon Power knows all of the relevant information about this contract because, as Ms. Medine admits (p. 31), Mon Power has been operating under the same contract for years.

Q. What about Ms. Medine's comments (pp. 40–41) on the BTU assumptions associated with the coal under this contract?

A. If, for illustrative purposes, you were to assume a Btu adjustment of 13,000 Btu to 12,600 Btu, it would result in approximately a 3% change in fuel costs for that contract for three years until it expires. Even if this illustration is assumed, the resultant fuel costs are still in line with the ABB forecast. Consequently, Ms. Medine's concerns about the Btu assumptions are unfounded.

Q. Why did Mon Power not insist that CRA use the most recent ABB forecasts available at the time it did its work?

A. When CRA and Mon Power were developing the RFP, the most recent ABB forecast available was the Spring 2016 forecast. Mon Power purchased that forecast from ABB in October 2016 to make sure we had a forecast in hand prior to issuing the RFP, which occurred in mid-December. Moreover – and this is the decisive factor on this point – the same ABB forecasts of natural gas prices, energy prices and capacity prices were applied

evenly across the NPV analyses of all conforming bids. As I've noted, using a different forecast might have changed the nominal value of the NPV analyses for each conforming bid, but it would not have changed the comparative ranking of those bids. Neither Mr. Schlissel (pp. 24–25) nor Mr. Comings (pp. 23, 26, 35) asserts that using a different forecast would have made a difference in comparative terms among the conforming bids.

Q. Mr. Schlissel and Mr. Comings also question the lack of a carbon price in the CRA analysis. Why did Mon Power not require this?

A. This would not have been a component of CRA's analysis that Mon Power would have dictated, and CRA could have made some assumption here applicable to all bidders. Nevertheless, I agree with Mr. Lee that the prospect of a carbon price is very uncertain; in fact, one might reasonably conclude that it is even less certain now than it was when the same issue arose in the Commission's consideration of the Harrison transaction in 2012/2013.

Section V Price Criticisms

Q. Certain intervenors argue that the proposed purchase price for Pleasants is too high, even though it was by far the lowest price bid. How do you respond to these points?

A. My first response is to remind them that one of the key benefits of an RFP is to remove non-market based considerations from the asset value determination. If an RFP is supposed to determine market value better than negotiations between affiliates, or through reference to supposedly comparable sales or impairment analyses, as all the

major parties had argued in the Harrison proceeding, then the purchase price determined in this RFP should be viewed as a reliable assessment of the fair market price. Again, this and other attributes of the RFP process received virtually no attention in the intervenor testimony – most likely because it is inconsistent with their earlier positions in the Harrison case that Mon Power should do an RFP and use the winning bid if better than buying from the market. I can confirm that Mon Power provided no advantage to AE Supply.

Q. Mr. Schlissel contends (p. 68) that the purchase price should be questioned because the Companies offered "no evidence" on why AE Supply offered $150 per kW for the Pleasants capacity. How do you respond?

A. To my knowledge, RFP processes do not require bidders to explain why they make the bids they do, or why they were not higher or lower instead. The Companies have no way of knowing why AE Supply made the offer for Pleasants that it did, just as they had no way of knowing why the sponsors of other conforming and non-conforming bids offered the prices that they did. These factors simply aren't an appropriate part of the RFP process.

Q. Ms. Medine (p. 57) and Mr. Baron (p. 7) criticize the outcome because the AE Supply bid price was not supported by an independent determination of market value or an impairment analysis. Do you agree?

A. No. In fact, such market valuation efforts outside of the RFP process were roundly criticized in the Harrison case by these same parties; again, they instead argued in that case that an RFP was the preferable method to establish a market price. Now that these

same parties do not like the results of their requested RFP, they revert back to proposing what they roundly criticized in the Harrison case. I should note, though, that Mr. Baron conceded in discovery that conducting an impairment analysis is "not necessarily" an appropriate way to determine the market value of a generating asset. WVEUG DR 1.

Q. Ms. Medine (pp. 18–19) and Mr. Schlissel (pp. 68–69) both contend that other recent capacity sales in PJM West were at lower per kW values than the AE Supply bid for Pleasants. Do you think these transactions provide a reliable basis for comparison?

A. No, nor do I think that they should be used to support or undermine an RFP-derived price. First, the notion that a market price can be established by looking at different transactions among different parties under different circumstances is totally inconsistent with the arguments these same intervenors made in the Harrison case about the advantages of using an RFP process instead of an appraisal approach. Second, one would need to do in-depth analysis of whether those sales truly are comparable and what the motivations of the buyers and sellers were, which no intervenor did. Although I have not done any analyses of these sales, I note that they involved sales of minority interests owned by Dayton Power & Light in the Miami Fort 7/8 and Zimmer plants to the majority owner who also operated the plants, and as such on their face they do not seem like comparable transactions at all. A more appropriate comparable would be the sale of the very same plant interests (Pleasants) by the very same parties (Mon Power and AE Supply) less than four years ago at a price of $733/kw. Third, one might just as easily contend that the transactions Mr. Schlissel and Ms. Medine identify were actually below market because the per kW price bid for Pleasants was higher. Finally, conclusions about

the market price of Pleasants can be inferred from the CRA NPV analysis which shows a positive net present value at the $150 per kW price versus the market. Witness Eads was the only other witness who performed such analysis and his results also showed a positive NPV.

Q. Were any of the intervenor witnesses able to identify any assets, whether inside or outside the APS Zone, that could provide capacity on a more cost-effective basis than Pleasants can provide at a purchase price of $150 per kW?

A. Ms. Medine could identify none, saying that "CAD did not perform its own evaluation of assets." She alleged that the APS Zone limitation was evidence that Mon Power simply "did not want to know" whether there were any assets outsize the APS Zone that might be cost-competitive – a completely unfounded contention in my view. CAD DR 26. Mr. Comings could not identify any, either, conceding that he had not performed an independent inventory of assets available either inside or outside the APS Zone; Mr. Schlissel said essentially the same thing. Sierra Club DR 21; WVCAG-SUN DR 17.

Q. Are there any other comments on the purchase price you would like to address?

A. Yes. Several points made by intervenor witnesses seem to stem from FirstEnergy's strategic initiative to exit the competitive generation business and focus on regulated operations. In one way or another, Ms. Medine, Mr. Baron, Mr. Schlissel, and Mr. Comings all contend that FirstEnergy's strategic decision should be interpreted to mean that no matter what amount AE Supply offered for Pleasants, that amount is too high because FirstEnergy does not want to keep Pleasants. Stated differently, they contend that because Pleasants has little or no value to FirstEnergy, it should have less value to

Mon Power than the contract price. In a similar vein, Mr. Baron (p. 15) and Mr. Comings (p. 15) suggest that because FirstEnergy doesn't want to keep Pleasants, West Virginia customers should not want it either. Mr. Baron (pp. 7, 27), Mr. Comings (pp. 13–14) and Ms. Medine (p. 14) also insist that FirstEnergy's determination to shed the risks of the generation business, which among other things entails eventually selling or closing Pleasants, means that the plant's continued operation is too risky under Mon Power ownership as well. And without a shred of evidence, Ms. Medine even contends (p. 19) that AE Supply could not sell Pleasants for what Mon Power has agreed to pay for it.

All of these arguments are flawed for many reasons, but the main reason is this: no matter how the buyer and seller evaluate the sale price, and no matter what has motivated each of them to consummate the transaction, each is trying to maximize its benefit from the transaction – AE Supply by bidding the highest price it thinks it can achieve in the RFP process and still win, and Mon Power by using that same process to identify the lowest bidder. There has been no evidence presented that Mon Power was motivated by any objective other than to address a capacity shortfall in the best and lowest-cost way possible for the Companies' customers.

The difference in value that a buyer and a seller assign to a particular asset is the basis of all market exchanges. Buyers and sellers have different economic circumstances and different needs. Mon Power is a vertically integrated utility that has a need for capacity to serve its customers and the customers of PE-WV. Mon Power's cost of capital and its operational and financial priorities are likely to differ from those of entities that are not vertically integrated utilities. Further, the Commission should be aware that

AE Supply is selling its other generation assets at a price much higher than the proposed Pleasants sale. It was recently announced publicly that LS Power will be buying other AE Supply assets for $825 million for a total of 1,615 MW of capacity. Certainly, that buyer found reason to purchase generation assets, and at a much higher average price ($511 per kW, as compared with the $150 per kW for Pleasants.

Finally, I would note that the land alone at Pleasants along the Ohio River is likely to be worth tens of millions of dollars. AE Supply publicly announced the sale of a portion of its Hatfield property (200 acres) for $40 million. Pleasants lies along a larger, more industrially attractive site being the Ohio River, and has over 1100 acres of land.

Section VI Pleasants – a Solid Asset with Real Value

Q. Several intervenor witnesses point to the age of Pleasants as a reason to question its value. Do you agree?

A. No, I do not. A utility with an obligation to serve customer load might prefer to own the newest, most advanced facilities available, if price and the impact on customer rates were of no concern. That is not the world we live in, however. One benefit of the RFP process is to evaluate assets based on their anticipated market performance under comparable condition assumptions, with the ***value*** to customers taking into account a wide range of facility characteristics, including bid price. This is why the RFP was designed as it was.

Q. Which party raised most of the "age" concerns?

A. Not surprisingly, this criticism came mostly from Longview witnesses, who might have been expected to emphasize Pleasants' age in comparison with their client's facility.

Longview witness, Thomas Burnett, voiced these concerns most directly, but in hollow, entirely unsupported ways.

Q. What do you mean?

A. First, Mr. Burnett tells the Commission (p. 4) that through his and Longview witness Nikhil Kumar's records review, he has concluded that the "testimony and records produced in this case do not establish that the proposed transaction is in the public interest." At the outset, I struggle to understand how Mr. Burnett purports to define the public interest for the Commission in this context, in what we believe is his first appearance before the Commission on any matter.

Mr. Burnett next concludes (p. 8) that based on available information, he cannot describe Pleasants as "modern" or "well maintained." When Mr. Burnett says in his testimony that Pleasants is not a "modern" plant, what he really meant (as he acknowledged in discovery) is that Pleasants is not "thoroughly modern . . . based on the design of a supercritical plant compared to the present modern supercritical plant." Longview DR 15. But we know that already, and the Companies have not contended that Pleasants is new or near-new. Mr. Burnett also disclaimed any intent to suggest that Pleasants has not been effectively modernized for its current operations (Longview DR 16), or that it is not "environmentally compliant to today's standards" (Longview DR 15). Of course, his concessions on these points make his view consistent with what we have said (and I still believe): that Pleasants is thoroughly ***modernized***, in the sense that it has had maintenance and upgrades over the years to maintain its operations and comply with new environmental requirements. In fact, it has Selective Catalytic Reduction ("SCR")

controls that surpass the controls at Mon Power's Fort Martin plant. This modernization is not meant to convert Pleasants into a brand new facility; it only means that these upgrades have put it in very good condition for a plant of its type and vintage. This is why the CRA-calculated NPV for Pleasants is so much higher than the same calculation for Longview, for example.[19] Plants can operate for decades longer than ever originally established if they are well maintained and capital replacements are made when needed.

Q. Do you agree with Mr. Burnett's allegation that Pleasants has not been "well maintained"?

A. No. The arguments Mr. Burnett offers for this allegation are tenuous at best. For example, he suggests (p. 9) that his analysis of Pleasants data "does not clearly identify what was performed to keep an almost 40-year old power plant to be considered modern or reliable for another 20 years." Mr. Burnett does not specify, however, what should have been performed in his view to achieve this undefined standard; nor does his assertion prove that Pleasants has not been well maintained. Similarly, Mr. Burnett observes (p. 24) that except for the boiler plant, the need for overall plant maintenance during the period shown in the table (which runs only through 2013) indicates the plant is not well maintained. The implication here is that if the plant's operations during the period of 2011 through 2013 did not require a high level of maintenance compared to previous years – in other words, that it did not manifest problems that required those higher levels of maintenance – then it must be poorly maintained. Essentially, Mr. Burnett appears to espouse a "heads I win, tails you lose" theory: if maintenance costs are

[19] Mr. Eads' exclusion of Longview from the results of some of his sensitivity analyses reflects this substantial difference. Eads direct, pp. 24-26.

high, the explanation must be poor maintenance; on the other hand, if maintenance costs are low, then the plant has been poorly maintained. These Longview comments fly in the face not only of Mon Power's and Black & Veatch's judgment, but also the opinions of the Staff engineers who both visited this plant for three days recently and who know this plant from decades of ownership by Mon Power and PE. They also are undermined in Mr. Evans' rebuttal testimony.

Q. Do you have any other observations about Mr. Burnett's claim that the plant is not "modern"?

A. Mr. Burnett explores this theme at pp. 31–33 of his testimony. He effectively asks the Commission to conclude that if Pleasants does not meet the technological or supercritical pressure thresholds of a new coal-fired plant, and if Pleasants is less efficient than such plants as a result, then by definition it is not "modern." What Mr. Burnett does not say is whether the plant is modernized. As I mentioned, this is a much more relevant consideration than the self-proving, self-serving proposition that the plant is not new and therefore is not modern.

Q. What assessment does Mr. Burnett offer of Pleasants' future operations?

A. Mr. Burnett contends (p. 10) that his review "lead[s] to a high degree of uncertainty as for the ability of this plant to meet its intended operation." This is pure speculation, and there is absolutely no reason to think that Pleasants' ability to operate in the future is subject to a "high degree" of an uncertainty at all. If this were the case, Mr. Burnett presumably would show the Commission that Pleasants' operations have been uncertain in the past – but he does not and cannot. To the extent there is future uncertainty as to

Pleasants' intended operation, this uncertainty is not a condition that Pleasants alone confronts. Mr. Burnett's client obviously knows that even brand new plants can have the potential for significant impairments to their operations. For example, historic data shows that although Longview's equivalent forced outage rate-demand ("EFORd") was only 1.41% in 2016, its EFORd exceeded 10% in each of the preceding four years, including an EFORd of 29.44% in 2014, when the plant was only a few years old. I believe, and the rebuttal of Mr. Leutheuser and Mr. Evans shows, that there is no reason to believe Pleasants is subject to a greater degree of uncertainty in its future operations than Longview or any other plant. Just as Harrison and Ft. Martin, Mon Power's other base load coal plants, continue to operate reliably, there is no reason to assume that Pleasants' future operations are any more subject to a "high degree of uncertainty" than those plants are.

In effect, all that Longview's witnesses can say is that Pleasants is "aging" and is not as good as a newer, more modern asset. Certainly, asset condition is important, but if age were the only consideration, then a generating plant still on the drawing point would prevail in an RFP, no matter what its cost. As Mr. Lee explains, the primary purpose of NPV analysis is to compare assets with different ages, fuel sources, locations, and cost profiles, based on the value they can be expected to provide under assumed future conditions. CRA's analysis took all of these factors into account, and AE Supply's offer of Pleasants vastly outpaced the other conforming bids in terms of ***value***, largely because of its bid price.

Q. Ms. Medine and Mr. Kollen for the WVEUG point to other costs they believe should be considered to assess the real, effective cost of Pleasants to customers. What is your response to these points?

A. Some of these witnesses' points seem reasonable for the Commission to consider, and in my view others are inappropriate. First, I believe that an assessment of the future costs associated with the impoundment would be reasonable, just as assessing future costs for the other bidders' facilities would be for those bids. That said, the timing and ultimate cost associated with the impoundment are uncertain. (Nevertheless, Mr. Lee has evaluated the NPV impact of factoring in these costs, and he states that this addition would not materially affect the comparative evaluation of the conforming bids.)

On the other hand, I disagree that the Pleasants bid should incorporate costs to close Pleasants and acquire replacement capacity, whether under the 15-year study period CRA used or the 20-year period used in the 2015 IRP. No party has shown that the age, maintenance profile, or any other aspect of Pleasants creates any reasonable likelihood that Pleasants will not continue to operate throughout these periods. To me, consideration of these costs is entirely speculative and would be inappropriate to include in the NPV analysis CRA conducted.

Ms. Medine makes two points relating to Pleasants coal supplies. First, she questioned why the coal inventory on the ground at Pleasants should be part of the Transaction. The answer is that coal and other inventory must go with the plant in order to operate it. The plant needs those items to run under any entity's ownership. But there is nothing unusual about a plant being sold with its existing fuel supplies. In fact, it

would be unusual if the coal inventory were not a component of the Transaction. It simply makes no sense that coal already delivered to Pleasants at the time of the closing should be moved again to another plant. Even if this were feasible, the high cost of transporting this coal a second time would make this a very poor choice. The Companies have no concern about including the cost of existing coal inventory as part of the Transaction.

Q. In your view, how should the Commission evaluate Pleasants as an asset in Mon Power's generation portfolio?

A. I think the Commission should satisfy itself that (i) Pleasants has an appropriate remaining service life and can provide that value throughout the forecast period, assuming normal maintenance and upkeep. If the Commission is satisfied on these points, the overwhelming price differential between Pleasants and the other conforming bids make this comparison easy to make.

Section VII Potential for Customer Benefit

Q. Several intervenor witnesses contend that the Companies have not proven that the CRA-derived 15-year NPV for Pleasants of $636 million will be the level of customer benefits over that span. How do you respond?

A. While the Companies are very comfortable with CRA's methodology, they certainly are not saying that this result is guaranteed or even a primary justification for Commission approval. The $636 million NPV figure results from one way to calculate and present the Pleasants potential benefits in comparison to market purchases, using a uniform set of

assumptions and price forecasts. Clearly there are other ways to calculate these benefits, and reasonable arguments can be made as to which forecasts are better and why and which assumptions should be made. Moreover, the sensitivity analyses that several intervenor witnesses suggest are not inappropriate in concept, and application of them, like the thirty-some scenarios that Mr. Eads considered for the Staff, is not an unreasonable exercise in conceptual terms. In other words, there are many relevant variables in any analysis of an asset's future, and changing any one or more of them will necessarily change the estimated benefit over the analysis period. The same is true for Pleasants. But it is the overwhelming conclusion that no other asset comes close to Pleasants in any evaluation.

Q. In your view, then, how should the Commission evaluate the Companies' evidence on net present value?

A. The predicate for my answer is the RFP process itself. In establishing the RFP process and retaining CRA to administer it, the Companies did not set out to prove any specific NPV benefit to customers. Instead, they set out to identify the best possible resource meeting Mon Power's requirements through a competitive solicitation. By identifying the highest relative net present value of customer benefit from among the conforming bids, the RFP process effectively identified the appropriate, market-selected capacity asset to meet the identified need. What that highest NPV turns out to be is less important than the facts that (i) it is positive, and can be expected to yield some benefit to customers over time; and (ii) it is materially higher than the other bids.

All this said, we do believe that CRA's $636 million NPV calculation shows that there is considerable reason to believe that Pleasants will generate market revenues that can be credited to reduce ENEC rates and supply a hedge against market volatility. Mr. Eads' testimony for the Staff shows that Pleasants provides a substantial benefit under a wide range of scenarios. While this benefit may not be the primary justification for approval, evidence of Pleasants' NPV certainly does point to a potential upside for customers that the Commission has considered to be important in the past.

Q. Do you believe there is any basis for the Commission to apply the "risk-sharing" proposals that intervenors such as Staff, WVEUG, and WVSUN-CAG propose?

A. No, and I agree with Mr. Valdes's analysis of this question in his rebuttal testimony. Mr. Baron acknowledges in discovery that the Companies' customers currently bear 100% of the market risks (and benefit from 100% of the market rewards) associated with the participation of Ft. Martin in PJM markets. WVEUG DR 12.[20] The same is true for Harrison and the operations of plants in which Mon Power has a contractual interest (Bath County, Hannibal, Grant Town, and MEA), Mr. Baron said. WVEUG DR 13.

Section VIII Preserving Pleasants' Contributions to the State

Q. What value do the intervenors attach to preserving the economic, employment, and tax base contributions of Pleasants?

A. Although these are very relevant considerations and are prominent in the Application, they receive very little attention in the intervenor testimony. This lack of interest might

[20] Mr. Schlissel agreed in his response to WVSUN-CAG DR 8.

be expected from Sierra Club, an entity long committed to shuttering coal plants. Sierra Club has no appreciable interest in the employment of West Virginians at Pleasants or related coal and supplier businesses, and presumably it has no compunction about putting hundreds employed by these businesses out of work. So, the absence of these considerations in Mr. Comings' testimony for Sierra Club is really no surprise.

For Longview and the ESC intervenors, economic impacts are important, but apparently only those generated or to be generated by their own facilities. The Commission understands that these are market competitors, and their respective facilities' economic impacts are another way they compete with both AE Supply and Mon Power in the regulatory arena. So, these parties' lack of concern for the preservation of Pleasants' economic, employment, and tax base contributions is unsurprising as well.

Q. What about WVSUN/CAG, CAD, and WVEUG?

A. In my view, the Commission might reasonably expect more from these intervenors about preserving Pleasants' contributions as an objective in this case. WVSUN/CAG and CAD purport to represent West Virginians, and WVEUG continually stresses the economic contributions that its West Virginia members actually do make. Yet among the five witnesses testifying for these parties, there is virtually zero consideration given to preserving the very same types of economic contributions that Pleasants provides.

Q. A number of these witnesses contend that there is no proof that Pleasants will discontinue operations. How do you respond?

A. Ms. Medine (pp. 7, 18-19) and Mr. Comings (p. 37) argue that if the Companies cannot affirmatively represent that Pleasants will cease operations in the absence of Transaction

approval, then this potential outcome should not be considered. Obviously, the Companies are not in a position to determine what happens with Pleasants if the Transaction is not approved, or to predict what that outcome will be – whether a sale to another party, or a cessation of operations. The Companies know only what the other parties do: that FirstEnergy has announced its intent to exit the competitive generation business. We leave it to the Commission to assess the possible outcomes if the Transaction is not approved, but we believe there is a reasonable expectation that a cessation of operations could occur. To the extent this potential exists, we believe it is important that the Commission evaluate the important benefits Pleasants provides and consider the preservation of those benefits in its deliberations.

Q: **What are some of the economic benefits of Pleasants power station and the purchase?**

A. The preservation of direct jobs at Pleasants is 240. The coal mining jobs are much greater and estimated to be 680 coal miners to supply the station and 1,358 associated jobs (indirect/contractors). The spinoff from the 240 Pleasants jobs is approximately 1.3-1.5 times that amount and for the coal jobs the spin-off employment is approximately 3 times. The economic impact is shown in Dr. Deskins' testimony to be $400-500 million per year. The B & O taxes are $11.5 million per year, the coal severance taxes are about $7.5 million per year, and the property taxes are $ 6 million per year. The payroll taxes are over $ 1 million per year for Pleasants only. The impacts are huge to the state and the region.

Section IX Conclusion

Q. Do you have any closing thoughts for the Commission to consider?

A. Yes. I believe the Commission should evaluate the Pleasants proposal as an opportunity for the Companies, their customers, and the State of West Virginia. Pleasants as an asset compares very favorably – and is even newer – than two other very strong, reliable assets in Mon Power's asset portfolio: Fort Martin and Harrison. Mon Power has an opportunity to acquire Pleasants at a very favorable price established by the exact process its stakeholders have long insisted that Mon Power use to procure capacity resources. Mon Power's use of a qualified, experienced consultant in CRA should assure the Commission that the RFP design, administration, and scoring were fair to all participants, and that AE Supply did not benefit from any undue advantage. Finally, there can be no debate that Pleasants is an extremely important contributor to the West Virginia employment landscape, with benefits that go far beyond the station itself. All of these factors make the Pleasants acquisition a positive outcome for the State and the Companies' customers, and I firmly believe the Commission should approve it.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

Exhibit JAR-1

Index

6. Reference Medine direct, page 14, lines 22-24. Do you believe that FirstEnergy's strategy to exit the competitive generation business is sufficient to prove the exercise of bias in (i) Mon Power's requirements for the RFP or (ii) CRA's design, administration, or scoring of the RFP? If so, please explain in detail why you believe this is so and provide any communications or documents that you believe support your conclusion.

Response

No. It is evidence of bias. Please see Medine Testimony, Sections 3, 4 and 6.

8. Do you believe that the fact that the AE Supply bid of Pleasants was the winning bid in the RFP is itself evidence of the exercise of bias in (i) Mon Power's requirements for the RFP or (ii) CRA's design, administration, or scoring of the RFP? If so, please explain in detail why you believe this is so and provide any communications or documents that you believe support your conclusion.

<u>Response</u>

No. As discussed in Medine Testimony, the fact that the AE Supply bid of Pleasants was the winning bid reflects the flawed RFP process. It is evidence that the Commission should consider. Please see Medine Testimony, Sections 3,4, and 6.

12. Reference Medine direct, page 18, lines 10-14. Do you believe that your conclusion that a sale of Pleasants to Mon Power under the terms of the APA is "extremely advantageous to FE compared to the likely alternatives" is sufficient to prove the exercise of bias in (i) Mon Power's requirements for the RFP or (ii) CRA's design, administration, or scoring of the RFP? If so, please explain in detail why you believe this is so and provide any communications or documents that you believe support your conclusion.

Response

Yes. Please see Medine Testimony Page 18, Lines 14-22, Page 19, Lines 1-15, and Sections 3 through 6.

13. Reference Medine direct, page 18, lines 10-14. Do you believe that your conclusion that a sale of Pleasants to Mon Power under the terms of the APA is "extremely advantageous to FE compared to the likely alternatives" is a sufficient basis for the Commission to conclude that the Transaction is (i) disadvantageous or unfair to the Companies' customers, or (ii) otherwise should not be approved? If so, please explain in detail why you believe this is so and provide any communications or documents that you believe support your conclusion.

<u>Response</u>

Yes. Please see answer to Question 12.

18. Do you believe that in general, the use of a competitive RFP process:

    a. is a reasonable means for a load serving entity to identify the most cost-effective source of energy or capacity or both?
    b. is helpful in demonstrating what options are available in the market?
    c. allows a regulator to determine the costs and benefits of available options?
    d. is helpful in establishing the reasonableness of a transaction proposed to be consummated based on the RFP result?
    e. is helpful in establishing the market value of the asset to be acquired?
    f. is helpful in establishing that the value of the asset (as determined by the prevailing bid) is reasonable?
    g. Is helpful to ensure that no undue advantage is afforded to RFP participants, including affiliates of the RFP issuer?

In each case where you do not agree, please explain why.

Response

As a general proposition, yes. As explained in Medine Testimony, the manner in which *this* RFP was conducted none of these goals was accomplished.

20. Please identify any potential RFP respondent that was actually discouraged, deterred, or prevented from qualifying to bid or submitting a responsive bid due to the timing of the RFP process or the period for responses for prequalification or bid preparation or both.

a. For any such potential respondent, please provide the complete basis for your knowledge and copies of any documents that support that knowledge.
b. For any such potential respondent, please summarize your communications with that person or others representing that person, and provide copies of any such communications.

<u>Response</u>

Without waiving its previous objections to this question:

CAD objects to the form of this question. Without waiver, neither CAD nor Witness Medine had direct communications with "any potential RFP respondent that was discouraged, deterred, or prevented" from submitting a responsive bid. For the reasons provided in Medine Testimony, there is every indication that CRA sought to limit potential RFP respondents through the timing and scope of the RFP. The published response on the RFP website indicating that Mon Power was not interested in PPA's regardless of pricing confirms this.

24. Do you believe that there is any legitimate basis on which a load serving entity could prefer a physical asset to a PPA?

a. If so, please specify each such basis.
b. If any of the legitimate bases you identified in response to subpart (a) is one that Mon Power has advanced in this case, please indicate whether you believe that Mon Power's reliance on it in this case is nonetheless unreasonable.
c. If you do believe that Mon Power's reliance on that basis is nonetheless unreasonable, please explain in detail the basis for this belief.

<u>Response</u>

Without waiving its objections to this question:

a.-b. There may be legitimate reasons but not without analysis and support, none of which was provided by Mon Power. Likewise, there are reasons why a PPA would be preferred over a physical asset. None of these were addressed either.
c. Please see Medine Testimony Sections 3 through 6.

25. Do you believe that there is any legitimate basis on which Mon Power could prefer an asset in the APS Zone to an asset outside the APS Zone?

a. If so, please specify each such basis.
b. If any of the legitimate bases you identified in response to subpart (a) is one that Mon Power has advanced in this case, please indicate whether you believe that Mon Power's reliance on it in this case is nonetheless unreasonable.
c. If you do believe that Mon Power's reliance on that basis is nonetheless unreasonable, please explain in detail the basis for this belief.

Response

a. It is not CAD's job to provide a justification. CAD's position is that if there were justifiable reasons for the APS Zone limitation, Mon Power did not provide them. The APS Zone is not a constrained zone, is not modeled separately by PJM, and passes the CETO/CETL test.
b. See response to 25 (a)
c. See response to 25 (a)

26. Do you believe there are generating assets inside or outside the APS Zone that would provide capacity on a more cost-effective basis than Pleasants could provide at a purchase price of $150 per kW? If so, please identify each asset, state whether it is available or potentially available for sale, provide its known or estimated market price per kW, and explain why it would be a better capacity resource than Pleasants.

Response

Without waiving its objections to this question:

CAD believes that Mon Power did not want to know whether there were generating assets outside of the APS Zone that would have been more cost-effective, hence the APS Zone limitation. CAD did not perform its own evaluation of assets. More importantly, according to the Company's responses to CAD 6-C-8 and CAD 6-C-11, neither did the Company nor its representatives.

31. Reference Medine direct, page 31, line 3 to page 32, line 17. With respect to your assertion that items were noticeably missing from the referenced contract summary, please state whether you believe the absence of those items from the summary:

a. impaired CRA's or Mon Power's consideration of AE Supply's offer of Pleasants;
b. misled CRA or Mon Power in its consideration of AE Supply's offer;
c. invalidated or disqualified AE Supply's offer; or
d. had, or should be determined to have had, any consequences relevant to the issues presented in this case.

In each case, please explain your position.

Response

Yes to all. Please see Medine Testimony Page 32 Line 18 through Page 38 Line 8.

57. Please indicate whether Ms. Medine has ever participated in the design, development, administration, or scoring of an RFP for capacity resources issued by or on behalf of a load serving entity. If so, please specify, when, for whom, and in what capacity, and provide copies of or links to the RFP(s).

<u>Response</u>

EVA has not managed an RFP for capacity resources. EVA has managed multiple RFPs, has audited multiple RFPs including RFPs for renewables, and has supported participants in capacity auctions. Ms. Medine participated in many of these engagements.

LONGVIEW POWER, LLC'S RESPONSES TO
THE COMPANIES' FIRST DATA REQUEST
P.S.C. CASE NO. 17-0296-E-PC

Prepared By: Steven Gabel
President, Gabel Associates, Inc.

To Testify: Steven Gabel

Date Prepared: September 15, 2017

REQUEST NO. 8:

Reference Gabel direct, page 19, line 26 to page 20, line 15. Does the fact that under PJM rules, there is no requirement that the Companies own as much unforced capacity as their PJM capacity obligation mean that:

a. The Companies may not evaluate their capacity needs from the standpoint as West Virginia utilities with obligations to customers and choose to own more capacity than the PJM requirement?

b. The Commission may not evaluate the capacity need of a jurisdictional electric utility and choose to authorize the utility to own more capacity than the PJM requirement would specify?

In each case, please explain why or why not.

RESPONSE NO. 8:

a. No. Mon Power is free to seek the Commission's approval of a proposal to acquire more capacity than is necessary and may execute such a transaction if the Commission determines it to be in the public interest. As noted in the Commission's Management Summary Report 2014, "Mon Power actually bids its capacity and energy into the PJM market and buys back the amounts required to meet internal load requirements. This approach is designed to maximize revenue from sales into the PJM market and minimize the cost of meeting internal load." (See the Commission's 2014 Management Summary Report at Page 90 Note 4. Available at http://www.psc.state.wv.us/Mgmt_Sum/MSR2014_Report.pdf). The PSC considers the buy-back from the market as the equivalent of meeting internal load from internal sources except in instances when the buy-back exceeds sales into the PJM market." In this proceeding, Mon Power states that the Transaction is needed "in order to provide the energy and capacity needed to meet the Companies' projected requirements through 2022, minimizing or eliminating the need to rely on market purchase during that period . . . [and] will reduce market risk by providing an effective physical and financial hedge against

RESPONSE NO. 8: [Continued]

future capacity and energy price volatility." (See Direct Testimony of Holly C. Kauffman Page 5 of 15). However, a hedge is "effective" only if the produced commodity (i.e. capacity MWs) or cash flows (i.e. revenues from capacity sales to PJM) from the underlying instrument (i.e. Pleasants) are reasonably likely to offset the corresponding costs (i.e. the cost of capacity charged to Mon Power's customers by PJM). The Transaction is not an effective hedge because it obligates customers to purchase and carry the costs of a capacity resource that is too costly and far exceeds a reasonable forecast of future capacity needs.

b. No. The Commission is obligated to evaluate transactions such as the one at issue here to "ensure that rates and charges for utility services are just, reasonable, applied without unjust discrimination or preference" (West Virginia Code Ch. 24 Article 1 § 24-1-1 (a) 4). As noted above, Mon Power has predicated the Transaction on the basis of its alleged value to customers as a hedge against future needs and market capacity prices. The reasonableness and accuracy of this position should be reviewed by the Commission to assure that ratepayers are protected from unreasonable costs and risks.

LONGVIEW POWER, LLC'S RESPONSES TO
THE COMPANIES' FIRST DATA REQUEST
P.S.C. CASE NO. 17-0296-E-PC

Prepared By: Steven Gabel
President, Gabel Associates, Inc.

To Testify: Steven Gabel

Date Prepared: September 15, 2017

REQUEST NO. 11:

Reference Gabel direct, page 20, lines 5-7.

a. Should the fact that the Companies are winter-peaking utilities have any significance to them in terms of decision-making on the ownership of capacity resources or rights to capacity resources? Please explain why or why not.

b. Should the fact that the Companies are winter-peaking utilities have any significance to the Commission in terms of decision-making on the ownership of capacity resources or rights to capacity resources? Please explain why or why not.

c. For the purpose of decision-making on the ownership of capacity resources or rights to capacity resources, do you believe that there are any considerations the Companies should take into account other than the Companies' PJM capacity obligation as you define it? Please explain why or why not, and if there are other such considerations, please identify them.

RESPONSE NO. 11:

a. Yes. PJM's approach to assuring adequate capacity recognizes year-round requirements including winter as does the values related thereto.

b. Please see answer above.

c. Yes, considerations the Commission and the Companies should take into account include energy value, and energy or capacity hedge value that a proposal may provide.

LONGVIEW POWER, LLC'S RESPONSES TO
THE COMPANIES' FIRST DATA REQUEST
P.S.C. CASE NO. 17-0296-E-PC

Prepared By: Thomas Burnett
Technical Director – Power Generation
Intertek AIM Engineering Group

To Testify: Thomas Burnett

Date Prepared: September 15, 2017

REQUEST NO. 15:

Reference Burnett direct, page 4, lines 8-9. Please explain how you determined what the "public interest" consists of in the context of the Commission's evaluation of the Pleasants transaction, and provide the definition of the term you used for purposes of this testimony.

RESPONSE NO. 15:

The sum of the assumptions made for determining the financial benefit of the public did not appear to be reasonable based on the historical data as provided by Allegheny Energy Services Company as discussed in my testimony on pages 26 through 31.

The description of the plant as a thoroughly modern plant is not accurate based on the design of a supercritical plant compared to the present modern supercritical power plant. The plant appears to be environmentally compliant to today's standards. This opinion is provided in pages 31 through 33 of my testimony.

LONGVIEW POWER, LLC'S RESPONSES TO
THE COMPANIES' FIRST DATA REQUEST
P.S.C. CASE NO. 17-0296-E-PC

Prepared By: Thomas Burnett
Technical Director – Power Generation
Intertek AIM Engineering Group

To Testify: Thomas Burnett

Date Prepared: September 15, 2017

REQUEST NO. 16:

Reference Burnett direct, page 8, lines 13-14. With regard to your statement that there is not sufficient information to describe the plant as a "modern well maintained plant":

a. Does this necessarily suggest or prove that Pleasants has not been effectively modernized for the operations it now undertakes?

b. What additional information would you have needed to determine whether or not Pleasants is a well maintained plant?

RESPONSE NO. 16:

a. It does not.

b. The additional information needed was discussed I my testimony beginning at line 3 on page 25 and continuing through line 4 on page 26.

Case No. 17-0296-E-PC
Companies' First Data Request to Sierra Club

The following objection to Question No. 1 of the Companies' First Data Request to the Sierra Club has been prepared under my supervision.

Evan D. Johns
Appalachian Mountain Advocates
Counsel for the Sierra Club

The following response to Question No. 1 of the Companies' First Data Request to the Sierra Club has been prepared under my supervision.

Tyler Comings
Energy Economics Consultant

Question No. 1

Reference Comins [sic] direct, page 2, line 26 to page 3, line 7.

a. Do you believe the Companies could meet their entire "obligations as prescribed by PJM" with market purchases?
b. If your answer to subpart (b) is no, please explain to what degree the Companies are obligated to have steel-in-ground to cover their obligations as prescribed by PJM.

Response

The Sierra Club objects to Question No. 1 to the extent subsection (b) requests information that is equally available to the Companies as it is to the Sierra Club and calls for Mr. Comings to render a legal conclusion concerning the Companies' "obligations as prescribed by PJM." Notwithstanding those objections, and without waiving them, Mr. Comings offers the following response:

a. Yes. However this is an unlikely scenario.
b. Not applicable.

Case No. 17-0296-E-PC
Companies' First Data Request to Sierra Club

The following response to Question No. 2 of the Companies' First Data Request to the Sierra Club has been prepared under my supervision.

Tyler Comings
Energy Economics Consultant

Question No. 2

Reference Comins [sic] direct, page 3, lines 5-6. Do you believe that using market purchases of capacity to meet a shortfall exposes ratepayers to capacity market price risk? Please explain why or why not.

Response

Yes, there are risks to ratepayers in purchasing or selling capacity. Like most markets, the capacity market is subject to price variations. Ratepayers are, however, also exposed to capacity market risks under the Companies' proposal because they would have more capacity to sell in a market with a substantial risk of continuing low capacity prices. *See* Comings Direct 15:15-26.

Case No. 17-0296-E-PC
Companies' First Data Request to Sierra Club

The following objection to Question No. 10 of the Companies' First Data Request to the Sierra Club has been prepared under my supervision.

Evan D. Johns
Appalachian Mountain Advocates
Counsel for the Sierra Club

The following response to Question No. 10 of the Companies' First Data Request to the Sierra Club has been prepared under my supervision.

Tyler Comings
Energy Economics Consultant

Question No. 10

Reference Comins [sic] direct, page 10, line 22 to page 11, line 4. In your view, does the fact that under PJM rules, there is no requirement that the Companies own as much unforced capacity as their PJM capacity obligation, mean that:

a. The Companies may not evaluate their capacity needs from the standpoint as West Virginia utilities with obligations to customers and choose to own more capacity than the PJM requirement?

b. The Commission may not evaluate the capacity need of a jurisdictional electric utility and choose to authorize the utility to own more capacity than the PJM requirement would specify?

In each case, please explain why or why not.

Response

The Sierra Club objects to Question No. 10 as it calls for Mr. Comings to render a legal conclusion. Notwithstanding this objection, and without waiving it, Mr. Comings offers the following response:

a. While I am not a lawyer, I believe the Companies *may* evaluate their capacity needs on whatever criteria they wish and that they may choose to own more capacity than PJM requires if doing so is reasonable and in the public interest.

Case No. 17-0296-E-PC
Companies' First Data Request to Sierra Club

b. While I am not a lawyer or an expert on the Commission's authority, I am unaware of any law or regulation preventing the Commission from authorizing a utility to own more capacity than PJM requires if doing so is reasonable and in the public interest.

Case No. 17-0296-E-PC
Companies' First Data Request to Sierra Club

The following objection to Question No. 17 of the Companies' First Data Request to the Sierra Club has been prepared under my supervision.

Evan D. Johns
Appalachian Mountain Advocates
Counsel for the Sierra Club

Question No. 17

Reference Comins [sic] direct, page 38, line 12. Apart from the requirements and design of the RFP, please identify any facts that you believe serve to prove the exercise of deliberate bias in favor of AE Supply or Pleasants. In each case, specify the persons involved and the time frame, and provide all related communications and documents.

Objection

The Sierra Club objects to Question No. 17 as beyond the scope of Mr. Comings's testimony, as requiring additional original work, and as not relevant or reasonably calculated to lead to the production of admissible evidence in this proceeding. Mr. Comings did not opine to whether any bias was "deliberate." Furthermore, whether any such bias was "deliberate" is not a relevant consideration in this proceeding.

Case No. 17-0296-E-PC
Companies' First Data Request to Sierra Club

The following response to Question No. 18 of the Companies' First Data Request to the Sierra Club has been prepared under my supervision.

Tyler Comings
Energy Economics Consultant

Question No. 18

Reference Comins [sic] direct, page 38, line 12. Do you believe that the fact that the AE Supply bid of Pleasants was the winning bid in the RFP is itself evidence of the exercise of bias in (i) Mon Power's requirements for the RFP or (ii) CRA's design, administration, or scoring of the RFP? If so, please explain in detail why you believe this is so and provide any communications or documents that you believe support your conclusion.

Response

No. My testimony discusses how the length and design of the RFP and the CRA analysis—not the ultimate result of the RFP—exhibit bias toward the transaction. While not *of itself* evidence of bias, the selection of Pleasants as the winning bid is consistent with my testimony identifying bias in the design of the RFP and in the CRA analysis.

Case No. 17-0296-E-PC
Companies' First Data Request to Sierra Club

The following response to Question No. 20 of the Companies' First Data Request to the Sierra Club has been prepared under my supervision.

Tyler Comings
Energy Economics Consultant

Question No. 20

Reference Comins [sic] direct, pages 38-39. Do you believe that in general, the use of a competitive RFP process:

a. is a reasonable means for a load serving entity to identify the most cost-effective source of energy or capacity or both?

b. is helpful in demonstrating what options are available in the market?

c. allows a regulator to determine the costs and benefits of available options?

d. is helpful in establishing the reasonableness of a transaction proposed to be consummated based on the RFP result?

e. is helpful in establishing the market value of the asset to be acquired?

f. is helpful in establishing that the value of the asset (as determined by the prevailing bid) is reasonable?

g. Is helpful to ensure that no undue advantage is afforded to RFP participants, including affiliates of the RFP issuer?

In each case where you do not agree, please explain why.

Response

a. Yes, if it is well-designed, fair, and encourages competitive bidding.

b. Yes, see response to subsection (a) above.

c. Yes, see response to subsection (a) above.

d. Yes, see response to subsection (a) above.

e. Yes, see response to subsection (a) above.

f. Yes, see response to subsection (a) above.

g. Yes, see response to subsection (a) above.

Case No. 17-0296-E-PC
Companies' First Data Request to Sierra Club

The following response to Question No. 21 of the Companies' First Data Request to the Sierra Club has been prepared under my supervision.

Tyler Comings
Energy Economics Consultant

Question No. 21

Reference Comins [sic] direct, pages 38-39. Do you believe there are generating assets inside or outside the APS Zone that would provide capacity on a more cost-effective basis than Pleasants could provide at a purchase price of $150 per kW? If so, please identify each asset, state whether it is available or potentially available for sale, provide its known or estimated market price per kW, and explain why it would be a better capacity resource than Pleasants.

Response

I have not performed an independent inventory of assets available inside or outside of the APS Zone.

Case No. 17-0296-E-PC
Companies' First Data Request to Sierra Club

The following objection to Question No. 22 of the Companies' First Data Request to the Sierra Club has been prepared under my supervision.

Evan D. Johns
Appalachian Mountain Advocates
Counsel for the Sierra Club

The following response to Question No. 22 of the Companies' First Data Request to the Sierra Club has been prepared under my supervision.

Tyler Comings
Energy Economics Consultant

Question No. 22

Reference Comins [sic] direct, pages 38-39. Do you believe that there is any legitimate basis on which a load serving entity could prefer a physical asset to a PPA?

a. If so, please specify each such basis.

b. If any of the legitimate bases you identified in response to subpart (a) is one that Mon Power has advanced in this case, please indicate whether you believe that Mon Power's reliance on it in this case is nonetheless unreasonable.

c. If you do believe that Mon Power's reliance on that basis is nonetheless unreasonable, please explain in detail the basis for this belief.

Response

The Sierra Club objects to Question No. 22 as not relevant or reasonably calculated to lead to the production of admissible evidence in this proceeding. The "preferences" of a load serving entity are not a relevant consideration in this proceeding. Notwithstanding this objection, and without waiving it, Mr. Comings offers the following response:

Yes, there can be certain advantages in owning a generic physical asset over entering into a generic PPA, depending on the structure of the PPA and asset transaction. Whether those advantages constitute a "legitimate basis" for a resource decision depends on their impact on ratepayers and on the public interest.

Case No. 17-0296-E-PC
Companies' First Data Request to Sierra Club

a. I did not evaluate each and every advantage or disadvantage of a generic PPA compared to a generic physical asset. There are advantages and disadvantages to all resource options.

b. Not applicable.

c. Not applicable.

Case No. 17-0296-E-PC
Companies' First Data Request to Sierra Club

The following objection to Question No. 23 of the Companies' First Data Request to the Sierra Club has been prepared under my supervision.

Evan D. Johns
Appalachian Mountain Advocates
Counsel for the Sierra Club

The following response to Question No. 23 of the Companies' First Data Request to the Sierra Club has been prepared under my supervision.

Tyler Comings
Energy Economics Consultant

Question No. 23

Reference Comins [sic] direct, pages 38-39. Do you believe that there is any legitimate basis on which Mon Power could prefer an asset in the APS Zone to an asset outside the APS Zone?

a. If so, please specify each such basis.

b. If any of the legitimate bases you identified in response to subpart (a) is one that Mon Power has advanced in this case, please indicate whether you believe that Mon Power's reliance on it in this case is nonetheless unreasonable.

c. If you do believe that Mon Power's reliance on that basis is nonetheless unreasonable, please explain in detail the basis for this belief.

Response

The Sierra Club objects to Question No. 23 as not relevant or reasonably calculated to lead to the production of admissible evidence in this proceeding. Mon Power's "preferences" are not a relevant consideration in this proceeding. Notwithstanding this objection, and without waiving it, Mr. Comings offers the following response:

Yes, there may be certain advantages to owning a generic asset in the APS Zone. There could also be advantages to owning a generic asset outside of the APS Zone. Whether those advantages constitute a "legitimate basis" for a resource decision depends on their impact on ratepayers and on the public interest.

Case No. 17-0296-E-PC
Companies' First Data Request to Sierra Club

a. I did not perform an independent evaluation of the advantages or disadvantages of owning a generic asset within the APS Zone as compared to a generic asset outside of the APS Zone.

b. Not applicable

c. Not applicable.

Case No. 17-0296-E-PC
Companies' First Data Request to Sierra Club

The following response to Question No. 24 of the Companies' First Data Request to the Sierra Club has been prepared under my supervision.

Tyler Comings
Energy Economics Consultant

Question No. 24

Reference Comins [sic] direct, pages 38-39.

a. Please identify any potential RFP respondent that was actually discouraged, deterred, or prevented from qualifying to bid or submitting a responsive bid due to the timing of the RFP process or the period for responses for prequalification or bid preparation or both.

b. For any such potential respondent, please provide the complete basis for your knowledge and copies of any documents that support that knowledge.

c. For any such potential respondent, please summarize your communications with that person or others representing that person, and provide copies of any such communications.

Response

There is no way for me to know this information, demonstrating the importance of ensuring the reasonableness of an RFP's design and timeframe as the only means of ensuring the RFP process elicits sufficient market information.

Case No. 17-0296-E-PC
Companies' First Data Request to Sierra Club

The following response to Question No. 26 of the Companies' First Data Request to the Sierra Club has been prepared under my supervision.

Tyler Comings
Energy Economics Consultant

Question No. 26

Please indicate whether you have ever participated in the design, development, administration, or scoring of an RFP for capacity resources issued by or on behalf of a load serving entity. If so, please specify, when, for whom, and in what capacity, and provide copies of or links to the RFP(s).

Response

No.

CASE NO. 17-0296-E-PC
Monongahela Power Company and The Potomac Edison Company

West Virginia Energy Users Group's ("WVEUG")
Responses to Companies' First Data Request

Question 1:

Reference Baron direct, page 6, lines 17-20. Do you take the position that conducting an impairment analysis is an appropriate way to determine the fair market value of a generating asset? If yes, please explain why you believe this is so, identify any authoritative support for your position, and provide any analyses or documents you believe support your position.

Response:

Not necessarily. However, in the case of an affiliate transaction, an impairment analysis would provide a check on the reasonableness of the affiliate's offer. Other than the AE Supply offer price, it is my understanding that the only other information relied on by Mon Power to determine the value of the Pleasants Station was the CRA economic analysis.

Prepared by: Stephen J. Baron
Principal and President, J. Kennedy and Associates, Inc.

Date: September 15, 2017

CASE NO. 17-0296-E-PC
Monongahela Power Company and The Potomac Edison Company

West Virginia Energy Users Group's ("WVEUG")
Responses to Companies' First Data Request

Question 12:

Reference Baron direct, page 15, lines 1-2. Please state whether the Companies' customers currently bear 100% of the market risks and benefit from 100% of the market rewards associated with the participation of Ft. Martin in PJM markets.

a. If so, please indicate whether the Commission has imposed any "protections" for customers in connection with the market operations of that plant.

b. Please state whether your answers would be different if the questions related to the operations of Bath County, Hannibal, Grant Town, or MEA.

Response:

Yes.

a. **I am not aware of any protections imposed by the Commission associated with the Ft. Martin generating plant, beyond the Commission's regulatory oversight of Mon Power's operation of the plant, including control of costs, performance of proper maintenance and other regulatory oversight.**

b. **My responses would be the same.**

Prepared by: Stephen J. Baron
Principal and President, J. Kennedy and Associates, Inc.

Date: September 15, 2017

CASE NO. 17-0296-E-PC
Monongahela Power Company and The Potomac Edison Company

West Virginia Energy Users Group's ("WVEUG")
Responses to Companies' First Data Request

Question 13:

Reference Baron direct, page 15, lines 1-2. Please state whether the Companies bear 100% of the market risks and benefit from 100% of the market rewards associated with the participation of Harrison in PJM markets.

a. Please state whether your answers would be different if the question related to the operations of Bath County, Hannibal, Grant Town, or MEA (other plants in which Mon Power has a contractual interest in the capacity or energy or both).

Response:

The Companies do not bear 100% of the market risks nor 100% of the market risks associated with the Harrison Station; rather, the Companies' customers bear the risks and receive the rewards.

a. My response would be the same for these other plants.

Prepared by: Stephen J. Baron
Principal and President, J. Kennedy and Associates, Inc.

Date: September 15, 2017

Case No. 17-0296-E-PC
Companies' First Data Request to WVSUN/CAG
Witness: David A. Schlissel
Date: September 15, 2017

RESPONSES TO REQUEST

6. Do you believe that an RFP process is not a reasonable way to establish a market price for a generating unit? If so, please explain in detail all of the reasons for this belief.

RESPONSE:

No. An RFP that is properly designed to be fair, transparent, and truly competitive can be a reasonable way to establish a market price for a generating unit.

Case No. 17-0296-E-PC
Companies' First Data Request to WVSUN/CAG
Witness: David A. Schlissel
Date: September 15, 2017

RESPONSES TO REQUEST

7. Do you believe that in general, the use of a competitive RFP process:

   a. is a reasonable means for a load serving entity to identify the most cost-effective source of energy or capacity or both?
   b. is helpful in demonstrating what options are available in the market?
   c. allows a regulator to determine the costs and benefits of available options?
   d. is helpful in establishing the reasonableness of a transaction proposed to be consummated based on the RFP result?
   e. is helpful in establishing the market value of the asset to be acquired?
   f. is helpful in establishing that the value of the asset (as determined by the prevailing bid) is reasonable?
   g. Is helpful to ensure that no undue advantage is afforded to RFP participants, including affiliates of the RFP issuer?

   In each case where you do not agree, please explain why.

RESPONSE:

Yes, in general, I agree with these statements. One caveat I would make is with respect to (c); I would qualify that statement so it reads "can help a regulator determine the costs and benefits of available options." This qualification is necessary because all of the costs and benefits of a resource option may not necessarily be revealed during an RFP process. The total costs and benefits of an option may become more fully known in a post-RFP due diligence process, and/or in a subsequent regulatory proceeding.

To be clear, in agreeing to the general statements listed above, I am not commenting on the Mon Power RFP process that preceded the filing of this case.

Case No. 17-0296-E-PC
Companies' First Data Request to WVSUN/CAG
Witness: David A. Schlissel
Date: September 15, 2017

RESPONSES TO REQUEST

8. Reference Schlissel direct, page 6, lines 23-27. Please state whether the Companies' customers currently bear 100% of the market risks and benefit from 100% of the market rewards associated with the participation of Ft. Martin in PJM markets.

   a. If so, please indicate whether the Commission has imposed any "protections" for customers in connection with the market operations of that plant.
   b. Please state whether your answers would be different if the questions related to the operations of Bath County, Hannibal, Grant Town, or MEA (other plants in which Mon Power has a contractual interest in the capacity or energy or both).

RESPONSE:

As a general matter, the Companies' customers bear all of the market risks associated with Fort Martin's participation in the PJM markets. An important caveat, however: I have not reviewed all of the PSC proceedings related to Fort Martin, so the Commission may have shielded customers from some market risks in a prior proceeding that I am unaware of.

a. See my response above.

b. I have not reviewed the contracts for these plants, so I cannot comment on them.

Case No. 17-0296-E-PC
Companies' First Data Request to WVSUN/CAG
Witness: David A. Schlissel
Date: September 15, 2017

RESPONSES TO REQUEST

10. Reference Schlissel direct, page 8, lines 13-15, and page 10, lines 12-16. Does the fact that under PJM rules, there is no requirement that the Companies own as much unforced capacity as their PJM capacity obligation, mean to you that:

   a. The Companies may not evaluate their capacity needs from the standpoint as West Virginia utilities with obligations to customers and choose to own more capacity than the PJM requirement?
   b. The Commission may not evaluate the capacity need of a jurisdictional electric utility and choose to authorize the utility to own more capacity than the PJM requirement would specify?

   In each case, please explain why or why not.

RESPONSE:

a. I disagree with the premise of this question, because if a utility participates in PJM's capacity market, it would not "need" to own more capacity than its daily UCAP. With that caveat, the Companies may choose to own more generating capacity than the UCAP assigned by PJM. Whether they can recover the cost of such capacity from ratepayers is a separate issue: that question is subject to a Commission determination that such costs are just and reasonable, and meet legal requirements (like those laid out in W. Va. Code sec. 24-2-12).

b. I disagree with the premise of this question, because if a utility participates in PJM's capacity market, it would not "need" to own more capacity than its daily UCAP. That said, the Commission can authorize a utility to own more capacity than the utility's PJM obligation, provided the Commission's actions are consistent with legal requirements.

Case No. 17-0296-E-PC
Companies' First Data Request to WVSUN/CAG
Witness: David A. Schlissel
Date: September 15, 2017

RESPONSES TO REQUEST

12. Reference Schlissel direct, page 9, lines 16-18. To you, would a situation in which Mon Power owned zero generating capacity and satisfied its capacity obligations by paying locational reliability charges to PJM, be an acceptable outcome for the Companies?
    a. If yes, please explain why.
    b. If no, please explain why, and also indicate the level of MP-owned capacity (by MWs owned or percentage of the PJM capacity requirement) at which you believe an acceptable outcome would be reached.

RESPONSE:

WVSUN/CAG's counsel contacted the Companies' counsel due to confusion over the phrase "acceptable outcome." Based on a subsequent communication provided by the Companies' counsel on September 8, 2017, Mr. Schlissel understands this question to be asking whether it would be okay if the Companies were in the situation described above (i.e., if "Mon Power owned zero generating capacity and satisfied its capacity obligations by paying locational reliability charges to PJM"). Based on that clarification, Mr. Schlissel answers as follows:

I am aware that there are load serving entities (LSEs) within PJM that do not own any generating capacity, and LSEs that do own capacity. From the perspective of PJM, there is no requirement that an LSE own generating capacity. In the context of this PSC proceeding, I am not recommending that Mon Power divest itself of its currently owned generating capacity. If the Companies filed a proposal with the PSC for Mon Power to divest all of its capacity, I cannot speculate on how I would evaluate or how the Commission would respond to such proposal.

Case No. 17-0296-E-PC
Companies' First Data Request to WVSUN/CAG
Witness: David A. Schlissel
Date: September 15, 2017

RESPONSES TO REQUEST

15. Reference Schlissel direct, page 12.
    a. Do you believe that there is any reason why Mon Power would want to have a "hedge" against price volatility in the energy and capacity markets?
    b. If yes, please identify each reason and explain why it would be beneficial.
    c. If not, please explain why not.

RESPONSE:

a. Yes.

b. The Companies may want to reduce the impact on customers of changes in annual ENEC rates resulting from potential volatility in wholesale energy and/or capacity market prices. To the extent this were a concern, Mon Power's current generation fleet provides such a hedge. Increased investments in energy efficiency and renewable resources also would represent hedges against potential volatility in the energy and capacity markets. I would note, however, that the proposed transaction, by exacerbating the Companies' energy surplus, would actually leave the Companies' customers more exposed to volatility in energy market prices, and thus would not serve as a hedge.

c. N/A.

Case No. 17-0296-E-PC
Companies' First Data Request to WVSUN/CAG
Witness: David A. Schlissel
Date: September 15, 2017

RESPONSES TO REQUEST

16. Reference Schlissel direct, page 12. Please state whether you agree with the positions expressed in this passage from Mr. Baron's direct testimony for WVEUG (page 11, lines 3-9), and for each position explain why you do or do not agree:

> "It is PJM's responsibility to insure adequate reliability in the APS zone in which the Companies operation; however, PJM does not provide any price protection to the Companies' customers that would mitigate the impact of higher PJM market capacity and energy prices. This is the role of Mon Power's owned and controlled capacity resources. By selling the output of these resources into the PJM capacity and energy market, and crediting the revenues in the ENEC, the Companies' owned capacity acts as a physical hedge to market purchases."

RESPONSE:

I have not read Mr. Baron's testimony and I am not aware of the context in which these statements were made.

Taking these statements in isolation, however, I generally agree with the first two sentences, which are consistent with PJM rules. (Note: the first sentence has a small typo: "operation" should be "operate.")

With respect to the last sentence, I agree that the Companies' currently owned capacity acts as a physical hedge to market purchases to the extent that the revenues from capacity and energy sales offset the costs of procuring power from PJM and satisfying the Companies' capacity obligation (through payment of the locational reliability charge). I would note, however, that the ownership of excess energy and/or capacity also exposes ratepayers to market risk. Moreover, as I discuss in my testimony, acquisition of the Pleasants plant would expose ratepayers to greater market risks and increased costs. So if Pleasants is a "hedge," it's an extremely expensive one.

Case No. 17-0296-E-PC
Companies' First Data Request to WVSUN/CAG
Witness: David A. Schlissel
Date: September 15, 2017

RESPONSES TO REQUEST

17. Do you believe there are generating assets inside or outside the APS Zone that would provide capacity on a more cost-effective basis than Pleasants could provide at a purchase price of $150 per kW? If so, please identify each asset, state whether it is available or potentially available for sale, provide its known or estimated market price per kW, and explain why it would be a better capacity resource than Pleasants.

RESPONSE:

Given that the market value of other coal-fired assets in western PJM is lower than Pleasants' purchase price, there may be other generating assets that could provide capacity on a more cost-effective basis than Pleasants. There may be other types of generation assets (CCGTs, CTs, renewables) that are more cost-effective as well. But I have not conducted an analysis of the cost-effectiveness of all generating assets inside and outside the APS Zone, so I cannot provide a definitive answer to this data request.

Case No. 17-0296-E-PC
Companies' First Data Request to WVSUN/CAG
Witness: David A. Schlissel
Date: September 15, 2017

RESPONSES TO REQUEST

21. Do you believe that there is any legitimate basis on which a load serving entity could prefer a physical asset to a PPA?

   a. If so, please specify each such basis.
   b. If any of the legitimate bases you identified in response to subpart (a) is one that Mon Power has advanced in this case, please indicate whether you believe that Mon Power's reliance on it in this case is nonetheless unreasonable.
   c. If you do believe that Mon Power's reliance on that basis is nonetheless unreasonable, please explain in detail the basis for this belief.

RESPONSE:

Yes.

a. If an LSE performed a thorough evaluation of the potential costs and benefits of different resource options, an LSE might conclude that a particular physical asset is less costly than a particular PPA. In that circumstance, the LSE might legitimately prefer a physical asset. There are other potential reasons – *e.g.*, if there were a transmission constraint that could limit the flow of power from that asset or if the physical generating asset had a more reliable operating history than the asset(s) that would provide the power under the PPA; if a state commission had an RPS specifically requiring an LSE to build or purchase wind or solar generation units; if the LSE's current generation portfolio were tilted in favor of a single resource, and the physical asset diversified that portions. Because LSEs operate in different states and RTOs, and because their individual circumstances vary greatly, I cannot provide an exhaustive list of reasons.

b, c. Companies' witness Ruberto cited several rationales on pages 11-12 of his testimony. The first cited rationale appears similar to the first basis I identified above (i.e., cost effectiveness). As to Mon Power's reliance on it, I would note that I did not analyze the RFP process (including the other bids submitted in that process) in any detail. With that caveat, I do think that Mon Power's reliance on a cost-effectiveness rationale is unreasonable here, because acquiring Pleasants would likely be hundreds of millions of dollars more expensive for ratepayers. Given the significant costs and market risks of the proposed transaction, it cannot be characterized as cost effective.

Case No. 17-0296-E-PC
Companies' First Data Request to WVSUN/CAG
Witness: David A. Schlissel
Date: September 15, 2017

RESPONSES TO REQUEST

22. Do you believe that there is any legitimate basis on which Mon Power could prefer an asset in the APS Zone to an asset outside the APS Zone?

    a. If so, please specify each such basis.
    b. If any of the legitimate bases you identified in response to subpart (a) is one that Mon Power has advanced in this case, please indicate whether you believe that Mon Power's reliance on it in this case is nonetheless unreasonable.
    c. If you do believe that Mon Power's reliance on that basis is nonetheless unreasonable, please explain in detail the basis for this belief.

RESPONSE:

I am aware that Companies' witness Ruberto has offered a rationale for Mon Power's decision to restrict its RFP to the APS zone (see page 10 of Ruberto Direct), but at this time, I have not independently evaluated the Capacity Performance penalty rules referenced in that portion of his testimony. Nor is that issue a focus of my testimony. Therefore, at this time I cannot opine on the questions posed in this data request.

Case No. 17-0296-E-PC
Companies' First Data Request to WVSUN/CAG
Witness: David A. Schlissel
Date: September 15, 2017

RESPONSES TO REQUEST

23. Please indicate whether Mr. Schlissel has ever participated in the design, development, administration, or scoring of an RFP for capacity resources issued by or on behalf of a load serving entity. If so, please specify, when, for whom, and in what capacity, and provide copies of or links to the RFP(s).

RESPONSE:

No.

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

Case No. 17-0296-E-PC

MONONGAHELA POWER COMPANY and
THE POTOMAC EDISON COMPANY

Petition for Approval of a Generation Resource
Transaction and Related Relief

REBUTTAL TESTIMONY OF
ROBERT J. LEE

September 18, 2017

Q. Please state your name, title and business address.

A. I am Robert J. Lee, a Vice President at Charles River Associates ("CRA"), a consulting firm headquartered at 200 Clarendon Street, Boston, Massachusetts, 02116. I submitted prepared direct testimony on behalf of Mon Power in support of its request for authorization to acquire the Pleasants Power Station ("Pleasants") from Allegheny Energy Supply (the "Proposed Transaction"). In that direct testimony, I described my role as independent administrator in the request for proposals ("RFP") process that led to the Transaction.

Q. What is the purpose of your rebuttal testimony?

A. I will respond to certain allegations and erroneous statements made by Longview, WV SUN/CAG, the Sierra Club, and CAD (collectively, "Intervenors") in their August 25, 2017 filings. Intervenors took issue with the design and administration of the RFP and CRA's scoring of bids. While the Intervenors have criticized certain assumptions and evaluation criteria used in the RFP, it is highly unlikely that their recommended changes to any of those assumptions or evaluation criteria would have led to a different bidder prevailing in the RFP. The significant price difference between AE Supply's bid to sell Pleasants and the bids of the other conforming bidders makes it highly likely that Pleasants would continue to represent the best option on a net present value ("NPV") basis under the RFP criteria as well as most reasonable scenarios of future operations and market conditions. Thus, while I will respond to the substance of and rationales offered for specific Intervenors critiques,

these critiques are not particularly telling because it would not have changed the winning bidder in the RFP.

Q. What specific allegations will you address?

A. I will respond to criticisms related to the RFP process itself including the timeline and process transparency. I will address criticisms of CRA's use of the NPV model to assess the expected customer impact of each conforming bid, including:

1. criticisms of the NPV model's use of a 15-year evaluation period,
2. price forecast data,
3. certain operating cost assumptions,
4. the generation dispatch model used, and
5. generator capacity factors.

I will also address CRA's decision not to consider certain potential future costs associated with environmental regulations, environmental liabilities and potential plant decommissioning costs. In addition, I will discuss and support CRA's use of an in-state fuel criteria as part of the RFP's non-price factors.

In addition to the criticisms related to the NPV analysis listed above, I will address intervenor comparisons between the Pleasants purchase price and the sale prices in other recent coal plant transactions as well as CAD's claims that bids for resources outside the Allegheny Power System ("APS") zone should have been considered because two of the conforming bids should have been "consolidated" into a single bid.

Criticisms of the RFP Process and Timeline

Q. What criticisms did Sierra Club, CAD, and Longview witnesses direct against the RFP process?

A. Sierra Club witness Tyler Comings (p. 39) and CAD witness Emily Medine (p. 21) criticized the process timeline, and Longview witness Steven Gabel (p. 25) contended that the RFP process was not sufficiently transparent.

Q. What were those parties' concerns about the process timeline?

A. CAD witness Medine described the response period as "condensed" and argued that conducting the RFP near the year-end holiday period was inappropriate. Sierra Club witness Comings contended that the one-week prequalification period was too short.

Q. How do you respond to these criticisms?

A. I think these criticisms are unwarranted. I explained in my direct testimony that the timeline was consistent with RFPs for capacity resources I have managed for electric utilities in other jurisdictions. No bidders expressed any general or specific concerns about the timeline being a barrier to participation. As noted in my direct testimony, one party had a conflict unrelated to the specific demands of this RFP process, but this was a reflection of that party's other commitments, not the RFP timeline.

The criticism about the duration of the prequalification period can be refuted based on process participation alone. The criticism seems to be that the one-week period discouraged participation since the process officially launched on December 16 and prequalification packages were due on December 23. However, eight generation facilities submitted prequalification packages, so the timeline was clearly

adequate. The information required to complete the pre-qualification documents and submit the notice was perfunctory, consisting only of the bidder's contact name, contact details, and facility name, location and the net demonstrated/planned capability (MW) of the facility. Again, this is the type of information that a sophisticated industry participant could prepare and submit with little time and effort.

CRA called and emailed potential bidders in advance of the pre-qualification deadline to ensure they were aware of the opportunity and to maximize participation.

Q. How do you respond to Mr. Gabel's criticisms of the process transparency?

A. Before I address these criticisms, it may be helpful to review what an NPV analysis is and why it was used to evaluate conforming bids. The NPV model is a tool developed by CRA to assess the customer impact of proposals. The model calculated an NPV based on estimated costs and revenues for each generation facility offered into the RFP. The costs and revenues themselves were based on price forecasts, CRA's generation dispatch model results, and unit-specific cost and operational data provided by RFP respondents. CRA's use of this type of model was described in detail in the RFP,[1] and these types of models are commonly used to estimate the financial implications of potential investments in generating facilities. They are also used in regulatory proceedings, in support of commercial investment decisions, and for internal planning and portfolio strategy purposes. In addition, often times RFP processes use factors in addition to NPV analyses to capture factors not easily

[1] Monongahela Power Company Request for Proposals for Power Supply Generation Facilities and/or Demand Resources ("Capacity RFP"), provided as Exhibit RJL-2 to my direct testimony, at p. 22 at § 4.2.3.

translated into a discounted cash flow analysis. This RFP was not unique in that regard.

With this background, Mr. Gabel's criticisms about process transparency are clearly unfounded and evidence a lack of understanding of how these processes are commonly undertaken. Mr. Gabel contends (p. 25) that CRA and Mon Power "did not provide clear and transparent information with regard to the manner in which competing offers would be evaluated." To support this claim, he alleges two "critical shortcomings" in the process: (i) that there was insufficient information on the relative weighting of price and non-price factors, and the relative weighting among non-price factors (pp. 25-26); and (ii) that the information provided on how the price factor would be evaluated was "misleading" because it allegedly induced bidders and potential bidders to believe that the NPV evaluation would take into account the full life cycle of each proposer's asset (pp. 26-28). On this second point, Mr. Gabel contends (p. 26) that the phrase "for the full transaction associated with each proposal," as used in RFP document, was misleading. Neither of these criticisms is warranted, and the each of them is entirely speculative.

Relative Weighting of Factors

Bidders were provided detailed information on the factors that would influence how their bid would be evaluated and scored. Based on my experience, the information provided to potential bidders about the evaluation and scoring is consistent with industry practice in competitive solicitations. CRA conducted follow up calls with bidders to talk through the aspects of their proposals. To the best of my

recollection, no bidders expressed any specific concerns or raised questions about the evaluation process or scoring on those calls. The apparent premise of Mr. Gabel's allegation here is that more bidders would have participated, or would have framed their bids in different ways, if only they had better understood the relative importance of price and non-price factors. Not only are these assertions speculative, my experience is that a full explanation of relative weightings and scoring processes is not typically a part of RFPs of this kind.

Moreover, parties contemplating participation in an RFP of this type generally know that there are many different factors that are weighed to evaluate dissimilar assets. Section 4.1 of the Capacity RFP set forth twelve pages of considerations that would be taken into account just to evaluate the cost aspects of the conforming bids. At page 23 of the Capacity RFP, we explained that to facilitate comparisons among qualified proposals, adjustments to the review process may be necessary, and that CRA would make those adjustments at its sole discretion. And at page 21, we indicated that proposals would be evaluated on the basis which provided the "best combination of value, risk, and reliability for Mon Power and its customers."

These RFP parameters show that the evaluation of conforming bids is a multi-dimensional process, and that while CRA would use a scoring process to evaluate and compare those bids, no bidder would be entitled to prevail on the basis of formulaic considerations taken in isolation, or otherwise to a scoring process that did not take the potential for adjustments into account. Consequently, I see no merit in Mr.

Gabel's view that the lack of full disclosure of CRA's evaluation methodology was somehow fatal to the process.

Allegedly Misleading Statements on NPV Evaluation Period

Mr. Gabel next alleges that the phrase "for the full transaction associated with each Proposal" in the context of CRA's NPV evaluation process misled bidders and potential bidders by suggesting that the NPV evaluation would necessarily take into account each proposal's entire service life. He also claims (p. 27) that this phrase created the false impression that the CRA evaluation would "fully take into account the relative value of assets of different vintage and useful lives." Mr. Gabel is speculating as to how bidders would have interpreted such language, and he has not presented any argument as to how the interpretation would have changed their decision on whether to bid or how to present the assets offered into the RFP.

First, there is absolutely no basis for a bidder or potential bidder to assume that each proposal would be evaluated on the NPV of its entire life cycle, as Mr. Gabel appears to suggest. This would mean that new facilities and existing facilities would be reviewed using NPV analyses with dramatically different time horizons, and presumably that each analysis would take into account decommissioning and capacity replacement costs at the end of its assumed service life. There was nothing in the RFP that required that CRA would use this approach. —which is not how CRA has previously administered RFPs and is not, in CRA's experience, reflective of industry norms. If this had been CRA's approach, then CRA certainly would have required each proposal to provide estimates of its decommissioning costs at the end of

its expected service life – something that was not required in the RFP. Given the disparity in NPV results for the bids under the analysis as designed, examining speculative, longer-term costs would not have altered the conclusions on the merits of the bids received.

Q. Certain Intervenors allege that the 15-year NPV evaluation period was not appropriate. Can you summarize those allegations?

A. Yes.

- Mr. Gabel argues (p. 29) that the 15-year evaluation period "is not reflective of how the different proposed generating assets would actually impact Mon Power Ratepayers," and Ms. Medine makes a similar argument (p. 53) on behalf of CAD; and
- Mr. Gabel argues (p. 30) that even though the 20-year evaluation period used in Mon Power's 2015 IRP "would still tend to short-change assets of younger vintage," it was still 33% longer than the period CRA used in the RFP NPV analysis

Neither of these allegations has merit. There is no single industry-accepted customer impact period to be used in an NPV analysis, and CRA chose here not to use a longer impact period for two reasons. CRA utilized a 15-year period because 15 years was appropriate to understand the relative economics of the competing bids. Assumptions regarding performance factors become much more speculative the further they are assumed to occur in the future and such cost factors have a comparatively small impact on NPV due to discounting. The 15 year analysis period was appropriate for

projected facility operations to reach a steady, long-term state under the forecasted market conditions.

Moreover, there was no legitimate basis for the assumption that the RFP NPV period should be the same as the 20-year forecast period Mon Power used in the 2015 IRP or to conclude that a 20-year or longer impact period would have materially affected the outcome of the RFP. To be clear, CRA determined in advance of the RFP that a 15-year evaluation period would be appropriate and, therefore, neither studied nor had any reason to explicitly project cash flows under any other time periods. But based on the outcome of CRA's analysis and the disparity in NPVs between the Pleasants Facility and the next-closest conforming proposal, extending the customer impact period almost certainly would not have made a difference, particularly given the impact of discounting.[2] The results of this RFP simply were not close. Table 2.1 of Exhibit RJL-1 to my direct testimony (CRA's opinion letter) shows that the Pleasants NPV per kW UCAP was far higher than its closest competitors.

Q. What is your response to the inconsistency in the NPV evaluation periods between the RFP and Mon Power's 2015 IRP?

A. There is no basis for this allegation. The RFP and 2015 IRP are fundamentally different processes and serve different purposes, and I see no relevance to the fact that they used different time periods. The purpose of an IRP is generally to review and

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2 In other words, the NPV associated with years 16-20 would have been relatively small for all bidders due to the effects of discounting in the NPV analysis.

plan for future utility resource needs, whereas the purpose of an RFP such as this is to evaluate and rank resources to meet a need that has already been identified. The forecast period used in an IRP has no bearing on an RFP or its analysis in my opinion. Different states use different time periods for IRPs, and in some states utilities conduct multiple IRPs covering different time periods. CRA was not involved in Mon Power's West Virginia IRP, and its role as an independent RFP administrator was not to engage in resource planning. Rather, CRA's role was to independently administer an RFP to meet Mon Power's identified capacity need. While there is no single acceptable customer impact period, in my professional judgment, a 15-year customer impact period was appropriate in this case for the reasons noted above and in my prior testimony. In any case, my assessment of an appropriate customer impact period for this or any other RFP generally is not based on the time period covered by the issuing utility's IRP.

Q. Multiple Intervenors allege that price forecasts used in the NPV model were too high. Can you summarize those allegations?

A. Yes.

- Mr. Gabel (pp. 6, 9), Ms. Medine (p. 44), and Mr. Schlissel (page 67) argue that the ABB natural gas, energy, and/or capacity price forecast data were too high, that CRA should have used lower price forecasts, and that as a result NPV calculations should be lower; and

- Ms. Medine argues (pp. 19, 48) that because the most recent PJM capacity auction cleared lower than ABB's forecasted price, the ABB capacity price forecast data must be too high.
- Mr. Schlissel (p 63) presented revised estimates of the Pleasants NPV based on adjustments to the CRA forecast of Pleasants revenues.

Q. What is your response to the allegation that the energy and capacity price forecasts used were too high and that CRA should have used lower price forecasts?

A. First off, future energy and capacity prices used in the evaluation were not CRA's estimates. These estimates were provided by ABB from its standard Spring 2016 Power Reference Case, and the source of these data was selected before the pre-qualification stage of the RFP. As such, CRA did not control the energy and capacity price assumptions used in the NPV analysis, nor was CRA's control of these data necessary to a fair RFP process. Mr. Sweet addresses the specifics in his rebuttal testimony.

Instead, CRA's objective was to identify a source of forecasted data that was reasonable, non-biased, and generally accepted in the industry, and the ABB semiannual reference case information met all of these requirements. For CRA's purposes, the critical point is that the same set of price forecasts is used in an even-handed way in the NPV analyses of each conforming bid; the fact that arguments can be made that any given forecasted data point might prove to be high or low after the fact is not especially relevant to our work, because in general terms any such

differences may not materially affect the relative NPV values of all the bids to which they were applied. In criticizing the ABB price forecast data and CRA's use of it in the NPV modeling, Mr. Gabel, Mr. Schlissel, and Ms. Medine focus not on the comparative NPV values our process generated, but on whether the Pleasants NPV should be considered as an accurate projection of the customer benefit/cost forecast over the fifteen-year NPV assessment period.

Q. Did CRA understand that AE Supply might participate in the RFP?

A. Yes, I had a general understanding that this might be the case. CRA understood that the Pleasants Facility was a facility potentially meeting Mon Power's needs as reflected in the RFP and, as such, was one of the [28] facilities CRA reached out to regarding the RFP. However, CRA did not know what other potential bidders might submit a bid or what facilities (existing or planned) might be involved Nor did CRA or Mon Power have any advance insights into the details of any bid that might be received through the process. As a result, while CRA never would have attempted to favor any one particular bidder in any event, here, CRA could not have select a forecast guaranteed to favor the Pleasants Facility because whatever forecast was selected may have been just as, or even more, favorable to another bidder.

Q. Did CRA's use of the ABB capacity price forecast affect the relative NPV calculations of the conforming bids, so that one bid was advantaged and others were disadvantaged?

A. No. Any suggestion that the ABB capacity price forecast materially affected the relative scoring of RFP proposals is false. While capacity prices affect the NPV

calculations for each proposal, they have relatively little effect on NPV differentials between competing proposals. The NPV model is applied in the same manner to each proposal, utilizing the same price forecast data. Therefore, while different capacity price forecast data could impact NPV values, it almost surely would not have been determinative of the ultimate winner of the RFP, and none of these witnesses has attempted to demonstrate this outcome. This is particularly true given the significant disparity between the winning proposal's NPV and the NPV of the next-closest proposal.

Q. What is your response to Ms. Medine's allegation (p. 9) that the most recent PJM capacity auction results demonstrate that the ABB price forecast is too high?

A. I reject this allegation. In my view, the fact that the most recent PJM capacity auction cleared below ABB's forecast is not significant to the long term analysis CRA performed. ABB's capacity price forecast is just that—a forecast. Forecasts will never be precise. Forecasts cannot be expected to predict prices exactly, but rather they are used to provide a reasonable assessment of future prices. While other forecasts may have, in hindsight, more closely predicted prices for the most recent PJM capacity auction, the forecast for that auction is just one price data point out of many used in the NPV model over the 15-year customer impact period. In the end, and with the benefit of hindsight, the ABB forecast may turn out to be more accurate or less accurate than other reputable forecasts, and it may turn out to have predicted prices that turn out to be above or below realized market prices—we will not know

for some time. But where prices ultimately settle over the course of the next 15 years has nothing to do with the reasonableness of using ABB data as a resource for the NPV model. Simply put, the ABB forecast data are from a reputable and reliable source that was appropriate to use in the NPV model.

Q. Multiple Intervenors allege that certain cost and performance parameters for Pleasants as modeled were inaccurate. Can you summarize those allegations?

A. Yes.

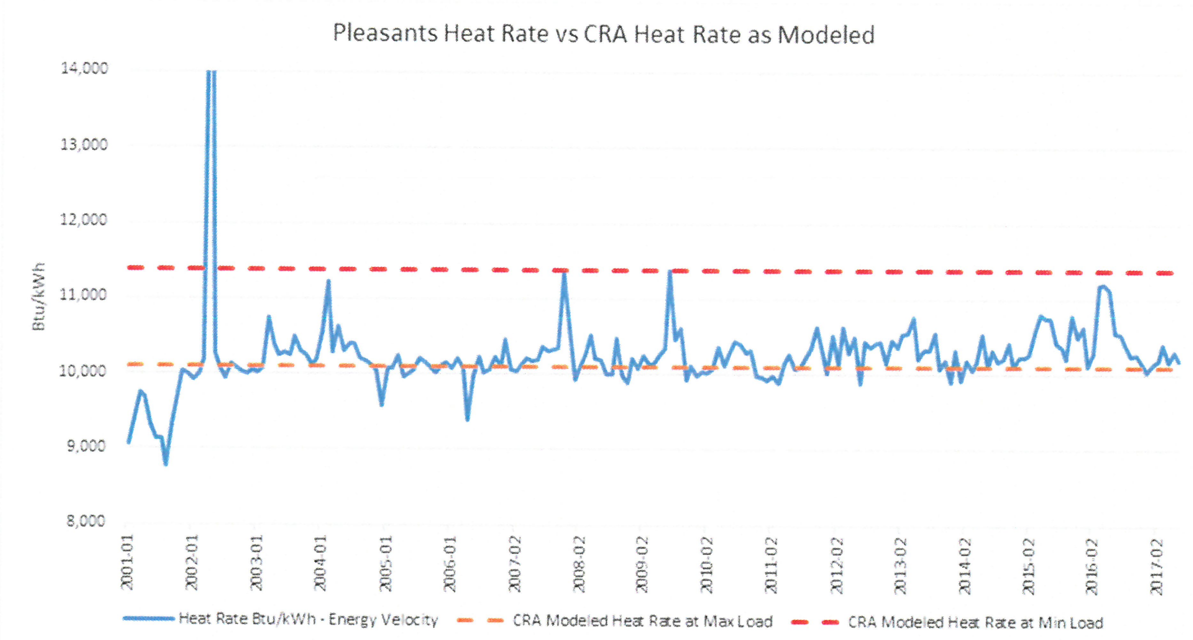
- Mr. Gabel claims (pp. 13, 14) that the heat rate as modeled was lower than recent historical performance, and variable operations and maintenance ("VOM") costs were below the PJM average for coal plants in PJM.
- Mr. Schlissel argues (p. 50) that CRA should have assumed declining performance for the Pleasants facility over the course of the NPV analysis.

Q. What is your response to the allegation that the heat rate used in the NPV model is not representative of recent history?

A. The allegation is without merit. The heat rate for a coal-fired power plant is not a single static number. Observed heat rates for the Pleasants facility and other fossil generating stations are a function of the physical capabilities of the plant as measured by the heat rate curve as well as the station loading and other factors. In the same way that the mileage per gallon observed for a car will vary depending on whether the car is driven in the city or the highway, whether the air conditioning is used, whether windows are open, and other factors, the observed heat rate for a power plant will depend on various conditions. It is not surprising that the as modeled heat rate output

from CRA modeling would not precisely match recent data history, just as the recent data history itself varies. Figure 1 below shows Energy Velocity data for the heat rate at Pleasants versus the minimum and maximum load heat rate for the facility from CRA modeling. As the figure illustrates, the dispatch modeling heat rates are in line with the range of actual facility performance. In addition, as can be seen from the figure, actual observed facility efficiency will vary over time.

Figure 1



Source: Energy Velocity

Q. What is your response to these allegations that the cost and performance parameters for Pleasants were not reflective of actual operations for the facility?

Longview argues that in modeling Pleasants, CRA should have favored industry-wide performance averages (Gabel, p. 14) or costs at other similar facilities (Kumar, p. 39) – in other words, that hypothetical cost assumptions are preferable to costs derived from actual operating performance of the facility in question. But operating costs at

power plants are not uniform, and the CRA approach of favoring actual operating data based on a multi-year analysis period is the approach we have used in similar RFPs conducted in the past. In addition, there may be cost classification issues to consider when comparing line item level costs for one facility to a similar line item at another. Some facilities may classify certain costs as variable while others consider them fixed. Some may capitalize certain costs while others expense them. Substituting line item level costs from one facility into the cash flow estimates for another facility creates risk of double counting or missing certain cash flows due to classification inconsistencies. Substituting industry wide average costs for actual costs risks missing the true plant level variation in the underlying data.

Q. Should the CRA analysis have included a provision for the shutdown?

No. I disagree with intervenors' claims (Medine, p. 10; Baron, p. 25; Comings, p. 6) that CRA's modeling should have incorporated the cost of shutting down Pleasants or other facilities, and I also disagree that doing so would have had a material impact on the identification of Pleasants as the winning bid in the RFP. First, I had no basis to believe that any facilities bid into the RFP would shut down during the 15-year NPV assessment period, and Pleasants' performance in the dispatch model does not suggest that it would do so during that period. Second, the net shutdown costs to be used are just as uncertain. While WVEUG Witness Baron looks at the raw dismantling costs for Pleasants based on the Depreciation Study filed in Case No. 06-1426-E-D, that raw cost ignores the potential value of the Pleasants site for future power project development.

Q. Multiple Intervenors allege that the generation dispatch model used by CRA was flawed. Can you summarize those allegations?

A. Yes.

- Ms. Medine claims (p. 8) that "[t]he industry standard for determining generation dispatch in a PJM-type market is a 24/7 model which dispatches against load and other generating capacity", and she also argues (p. 52) that the dispatch model should have dispatched plants against demand and other generation capacity rather than energy prices;
- Ms. Medine also contends (p. 43) that the model should have incorporated a range of energy prices and a "scenario analysis;" and
- Ms. Medine asserts (p. 51) that a different model would have predicted a lower capacity factor for Pleasants than CRA's model. Mr. Gabel (p. 17) and Mr. Schlissel (p. 5) also question the capacity factor or expected facility output used for Pleasants in the CRA model.

Q. What is your response to Ms. Medine's allegation that the dispatch model used by CRA is not the industry standard?

A. CAD's assertion that there is one industry standard dispatch model is simply incorrect. There are many dispatch models used in the industry, and no one model is necessarily superior. The appropriateness of a dispatch model depends on its purpose. Here, CRA performed a dispatch analysis based on its experience and expertise with similar competitive procurements. Because the objective in this case was to model the performance of individual generating units under certain assumed

market price projections, CRA's dispatch model was reasonable and the appropriate tool for the engagement. The type of model CAD describes was not necessary in order to assess the value of different plants.

Q. What is your response to the suggestion that CRA should have used a model that dispatches against load to evaluate the bids?

A. I disagree with this suggestion. The type of model CAD describes provides an assessment of overall ***market conditions***. However, the purpose of this analysis was not to perform a comprehensive review of overall market conditions. Rather, the purpose of the dispatch and NPV analysis used in this RFP process was to compare the ***relative*** economics of each of the plants bid into the RFP under consistent market conditions. CRA's generation dispatch model used in this RFP process was a tool designed specifically for that purpose and is well-suited for the needs of this engagement. The tool has been used by CRA for several years by CRA's power sector clients for investment decisions and analysis of portfolio and individual asset performance versus projections of market conditions. CRA has used the dispatch model for other clients in support of their RFP processes as well.

Q. Is CRA equipped to perform the kind of dispatch modeling Ms. Medine suggests?

A. CRA has significant experience in performing more complicated market modeling using the type of model CAD suggests. There are times when those models are an appropriate tool for a client engagement. However, integrated market modeling is a complex exercise that requires a much broader set of inputs than the CRA dispatch

model used in this RFP requires. Such models require detailed assumptions about the location, timing and size of new capacity builds. Such modeling would also generally include assumptions about changes in transmission constraints over time. These types of assumptions can have a significant and asymmetric impact on the relative economics of individual stations examined. When the purpose of an engagement is to examine the economics of individual facilities bid into an RFP, this is problematic because the relative values may be significantly affected by a handful of very specific CRA assumptions.

The use of an integrated market model would have added significant cost to the RFP process but offered very little incremental benefit. When we developed the RFP process, we did not know how many bids we would receive or the location of each of the facilities offered. Calibrating the model inputs and assumptions to ensure a reasonable capacity balance would have been time consuming and costly, and the primary purpose of the calibration would have been to generate reasonable market prices for power—essentially the same data as was provided by ABB. Like the CRA dispatch model, these integrated models require input assumptions that are typically derived from third-party forecasts. Integrated models do not somehow eliminate questions related to forecast accuracy, and in the context of a comparative evaluation of bids in an RFP, they increase concerns about forecast consistency. Because these models require such a broad set of inputs, they may need to be derived from multiple sources which themselves may be based on inconsistent assumptions.

Q. Many of the Intervenors have recalculated NPVs for Pleasants using adjustments to the parameters described above, including facility operating costs, energy and capacity market price estimates, facility dispatch and other factors. Do you agree with the revised NPV valuations in the context of CRA's work?

A. No. Where the purpose of an NPV analysis is to compare the value of assets, recalculating the analysis for a single asset and for none of the others is a fundamentally flawed approach. Aside from Staff witness Eads, other intervenors only revise the NPV analysis for Pleasants, and that approach fails to recognize that the RFP process was a relative exercise, designed to identify the facility that best meets Mon Power's needs. Adjustments to the assumptions for a single facility will yield different NPV results but the proposed changes would also need to be applied to other bids received. Lowering the power market prices certainly would lower the estimated market revenue for Pleasants and the facility's NPV, but it would have a similar effect on the NPV calculations for other bidders. Selectively changing the revenue and cost drivers for a single bidder is irrelevant and deceptive.

Q. Mr. Schlissel has presented a set of NPV estimates for Pleasants that range from negative \$249 million to negative \$640 million with a base case estimate of negative \$470 million. Do you agree with his methodology or conclusions?

A. No. First off, Mr. Schlissel has performed no independent modeling of the Pleasants facility or of the PJM market. He simply assumed certain levels of generation and revenues and mechanically recalculated numbers.

Q. Can you describe Mr. Schlissel's "Base Case"?

A. Yes. Mr. Schlissel first selected a generation level for Pleasants based on the most recent 12-month period, a period when natural gas prices at the Henry Hub were depressed. Under the Base Case, this level of generation is held fixed for his full forecast horizon. Based on his Figure 24, generation under the base case is about 8 million MWh per year. This is well below the facility's capability and about 7% below its observed output level from 2014 when natural gas prices were stronger. He paired this past level of generation with energy forward prices; peak prices rising from the mid $30s per MWh to over $40 per MWh based on his figure 23. He also adjusted the capacity price estimate downward significantly (p 61).

Q. Do you believe this is a reasonable approach for a "Base Case"?

A. No. First off, Mr. Schlissel's generation level is based on select historic data while market prices are from the forward market. He has presented no analysis that indicates that the recent level of generation is consistent with these future price estimates. His forward prices rise over time, but the facility output remains static. At the most fundamental level, his approach ignores that generation levels for facilities in PJM are related to the prevailing market prices.

In addition, contrary to the Schlissel Base Case approach, there's also an inverse relationship between energy prices and capacity prices in a market. If units earn less money in the energy market due to lower prices they may need to earn more from the capacity market to remain on line. Schlissel has not performed an analysis of whether his combination of energy and capacity prices could be expected to

achieve PJM reliability targets. While my characterization of the relationship between PJM energy and capacity prices is a simplification of the full market dynamics. There is no basis to assume Mr. Schlissel's assumptions are internally consistent or realistic. He has presented no support for the combination of factors he has chosen in his Base Case.

Q. Did Mr. Schlissel perform any market modeling to support his conclusions?

A. No. Mr. Schlissel simply fixed the output for the facility and valued it based on the energy market forwards. CAD witness Medine (p 48) criticized CRA's approach because it was not based on the type of model the industry would expect, specifically, that the CRA dispatch model "was not what the industry would consider to be a 24/7 generation dispatch model in regions such as PJM which is a highly connected integrated market". While I strongly agree with CAD's assessment of the CRA dispatch model, I do agree that modeling is required for a proper analysis of the PJM market and Mr. Schlissel's approach of selecting a generation level and an unrelated market price is not based on any analysis of the dynamics of the PJM market at all. Mr. Schlissel himself stated (p 60-61) that generation "will depend on plant-specific conditions and costs and market conditions such as generation from other plants that are selected for dispatch instead of Pleasants". However, while he recognizes the market complexity, he considers none of those factors in his own analysis and it is not reflected in his NPV results.

Q. What scenarios did Mr. Schlissel perform?

A. Mr. Schlissel included three additional scenarios in his analysis. First, he developed a High Case and a Low Case. High Case energy prices and facility output are 10% above the Base Case. Low Case energy prices and facility are 10% below the Base Case. In addition, he performed a "sensitivity" that used an AE Supply energy price forecast and generation levels.

Q. Where his scenarios informative?

A. Mr. Schlissel's scenario selection actually underscores why it is not always necessary to do scenario analysis. His High Case and Low Case are mirror images and include no market discontinuities. As his Figures 24, 25 and 26 illustrate, they simply provide a range of uncertainty around his Base Case which is effectively the average of the High and Low. And while a range of uncertainty may have some value if the range were based on different market outlooks, his range represents nothing more than a +/-10% on the Base Case. Not only do the scenarios provide no real insight into the facility operations, the market dynamics in PJM that may impact the facility value or how the facility may perform under specific, alternative assumptions, but he also fails to provide support for why 10% represents a reasonable range of uncertainty.

More specifically, however, the +/-10% on *both* market prices and generation are not reasonable assumptions. Even in the abstract, an increase or decrease in market prices of 10% may have a dramatically different impact on facility output. However, in reality electricity prices do not rise on their own; they rise because of

other changes in the market, demand, commodity fuel prices, environmental considerations or other factors. The *cause* of the change in price is critical because the Pleasants facility will react differently depending on what drives the change in price. Some factors that *increase* prices could *reduce* facility output while some factors that *reduce* market prices may *increase* Pleasants output. Put plainly, the Schlissel "scenarios" are a gross oversimplification of how power markets work and, as a result, offer no value.

Q. More generally, if CRA had included a "scenario analysis" taking into account a range of price assumptions, might that have changed the results of the bidding process?

A. No. First, explicitly modeling such scenarios would not have improved the RFP process or altered the relative economics of the NPV analysis for each of the proposals received due to the number of uncertainties related to future market conditions and regulation scenarios. There are an infinite number of potential scenarios for domestic power markets, and it would have been unrealistic and unnecessary to model every possible scenario. Choosing different scenarios would simply have meant that the intervenors would have argued that other scenarios should have been modeled and considered. More importantly, however, analyzing multiple scenarios produces multiple NPVs for each bidder, which would have significantly complicated the bid evaluation. The RFP administrator would be required to select a single scenario, take an average (both of which would be similar to single base case approach) or develop a complicated set of rules for evaluating each bid under a set of

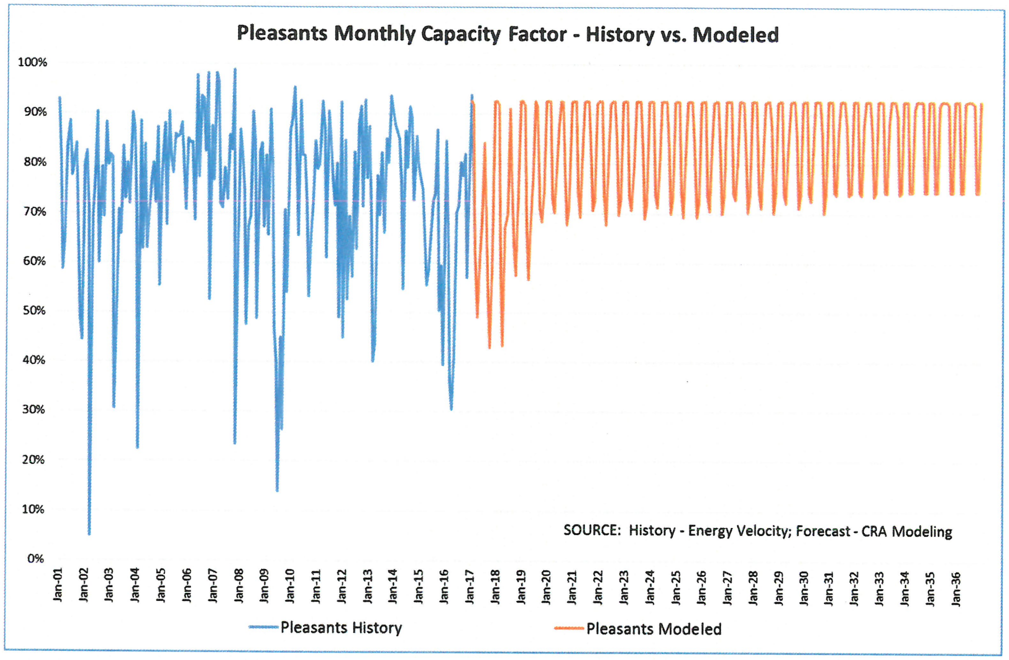
multiple NPV values. Developing that set of rules itself would be difficult because they would need to be determined in advance of receiving bids and performing any facility modeling.

Q. What is your response to the allegation that a lower capacity factor should have been used for Pleasants?

A. This allegation misrepresents the modeling process and the structure of the analysis. First, the Pleasants capacity factor was not a modeling *input* based on its recent observed performance, but rather was an *output* of the generation dispatch model based on the ABB price forecast and consistent with Pleasants operating parameters and demonstrated capabilities.[3] Second, Figure 2 below illustrates the historic monthly capacity factors (in blue) for Pleasants versus the monthly capacity factors generated as outputs of the CRA model (in orange).

[3] Mr. Schlissel recognizes this fact at footnote 77 of his testimony, where he attributes the operation of Pleasants in the dispatch model to the ABB energy price forecast.

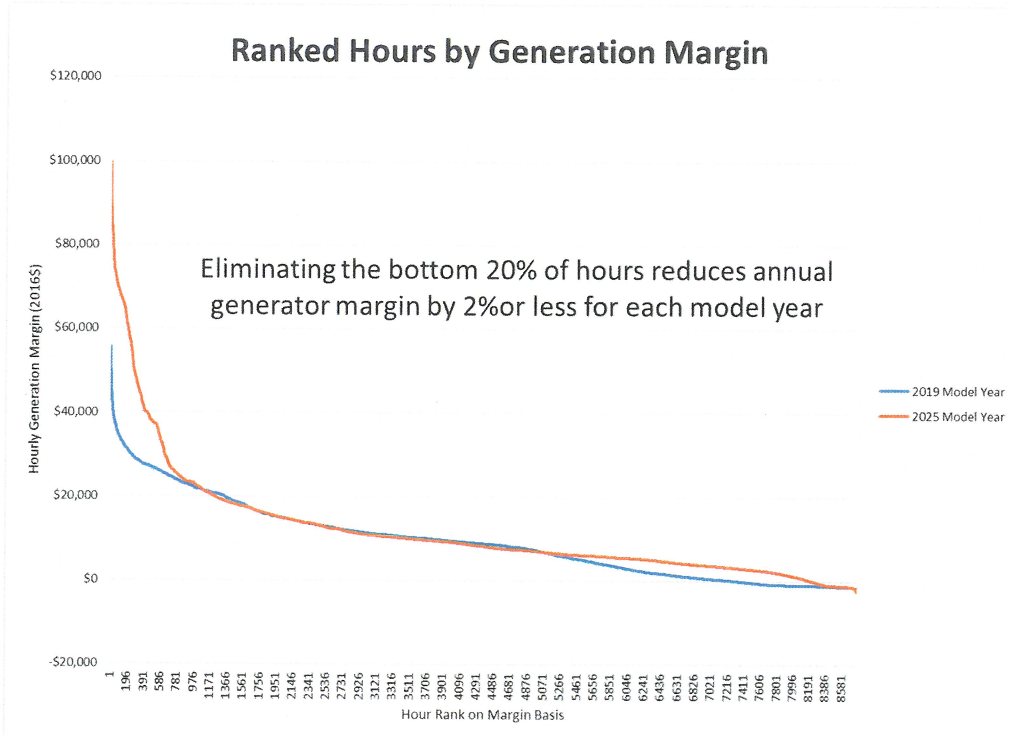
Figure 2



While both the projection and history show Pleasants operating at a high capacity factor in the majority of months, the data history does show a greater level of capacity factor volatility. That difference, however, is not uncommon when comparing modeled output to actuals. The primary reason for differences in modeled versus actual results is how models account for planned and forced outages. Forced and planned outages are typically modeled through a facility derate. That means some share of the outage is realized in every hour. In practice, however, outages occur at a discrete point in time leading to periods of very low output when the facility is offline. As a result, a wider range on capacity factors from recent history is to be expected. That does not mean that capacity factor outputs from the CRA model are unreliable, however.

In addition, in my experience capacity factors for baseload plants typically are not the most important factor related to plant profitability in the energy market. Plants in organized markets tend to earn a large portion of their energy market profits during a relatively small number of high-priced hours. In many operating hours, plants' marginal costs are close to their energy market revenues, meaning that whether the plant is running or not would not have a significant profitability impact. As a result, a small deviation in operating cost assumptions may have a dramatic impact on estimated capacity factors but very little impact on overall margins. Figure 3 below compares the energy margin yielded in each hour for Pleasants for the 2019 and 2025 model years. These years are largely representative of the facility performance in each year from the CRA modeling. In each case, the 8,760 hours are rank ordered largest to smallest based on the energy margin. In each case, eliminating 20% of the dispatch hours only reduces 2% or less of the energy margins earned by the facility over the course of the year.

Figure 3



Q. Ms. Medine questions (pp. 54-55) CRA's scoring of the in-state fuel consumption criteria. Can you explain CRA's scoring of that aspect of the RFP?

A. Ms. Medine questions why CRA gave AE Supply a score of 97 out of 100 on in-state sourcing of fuel when Pleasants received only 15% of its coal supply from West Virginia in recent years. She speculates that "either CRA was unaware of the actual purchasing history for the plant, or must have relied exclusively on any representations that may have been in AE Supply's offer about future West Virginia coal reliance." CAD also questions (p. 55) why Longview received zero points when the "lowest cost source of supply would be coal from one of the efficient longwall mines located on or near the Monongahela River or Ohio River such as Cumberland,

Tunnel Ridge or one of the Murray Energy West Virginia mines." Further, as far as I am aware, Longview itself has not questioned how their in-state fuel use was scored.

These concerns miss the actual facts. The RFP required respondents to provide information on their fuel sourcing, and provided that respondents who had historically sourced fuel from outside of West Virginia could submit proposals reflecting their ability to source fuel from within West Virginia and the costs of doing so. Capacity RFP at 16, § 4.1.4.3. CRA scored proposals on the in-state fuel sourcing criteria based on its review and analysis of the information provided in the proposals. AE Supply's score was based on Pleasants' demonstrated ability to source fuel from within West Virginia, and the estimated costs of doing so. Because Pleasants is located on the Ohio River, it has flexibility with respect to fuel sourcing and can reasonably source in-state coal by barge or rail. Therefore, CRA determined that the Pleasants Facility could indeed reasonably source fuel from West Virginia and scored its proposal accordingly. By contrast, CRA determined that the Longview facility sourced all or nearly all of its coal from the No. 4 West mine in Pennsylvania. Coal is delivered to the Longview Facility via conveyor belt. It does not receive coal via barge or rail, which may have provided access to coal from other source mines. While Longview could theoretically source some coal by truck, truck deliveries are less economical and truck transportation costs (even if Longview had provided them) would have been a significant uncertainty in our NPV modeling. Ms. Medine also suggests (p. 55) that Longview is located on the Monongahela River, but this is inaccurate; Longview would need to develop barge receiving facilities, and even if it

did, coal would need to be trucked from the barge receiving facilities to the Longview plant. In sum, CRA determined that Longview's ability to source coal from West Virginia is far more uncertain than AE Supply's. Further, the RFP document clearly states that if "a respondent has historically sourced fuel from outside of West Virginia, it may choose to provide detail on the costs that would be associated with sourcing fuel from within West Virginia (costs for commodity should be provided separately from transport) by submitting a separate Proposal." *Capacity RFP at 16, §* 4.1.4.3. Longview did not provide this detail in its response.

Q. Multiple Intervenors allege that the RFP failed to take into account certain potential future costs. Can you summarize those allegations?

A. Mr. Schlissel argues (p. 64) that CRA's evaluation should have taken into account capital expenditures to comply with the Effluent Limitation Guidelines ("ELG") and potential future costs associated with the McElroy's Run coal ash impoundment, estimated at $45 million. Ms. Medine asserts (p. 10) that CRA should have considered potential plant decommissioning costs (and capacity replacement costs).

Q. Do you agree with their positions on these points?

A. No, I do not; neither cost would have been appropriate to incorporate into the NPV analysis for Pleasants.

As an initial matter, it is important to remember that the RFP did require information regarding environmental compliance costs (Capacity RFP at 17, § 4.1.5.1), and CRA considered potentially relevant costs when evaluating proposals. But there is no single formula or mechanism for assessing and evaluating potential

environmental compliance costs and determining whether and how they should be included in an NPV analysis. In any RFP, certain environmental costs will be known or reasonably expected, while others will be more speculative and subject to change.

In my view, ELG compliance costs would have been reasonably viewed as uncertain and speculative, at best, at the time respondents submitted their proposals, particularly due to the pending change in administration and likely impacts on regulatory priorities and approaches. In fact, at the time the RFP was issued, the ELG rule was already being appealed to the United States Court of Appeals for the Fifth Circuit.[4] Since then, the EPA has announced that it will be reviewing and reconsidering the ELG rule and has issued an administrative stay of the rule.[5] In my view, these uncertainties made it inappropriate to assume these costs in the NPV model for Pleasants.

As for the McElroy's Run coal ash impoundment, there were many uncertain parameters that would have complicated any effort to include that potential cost in the NPV modeling. First, it is unclear when such costs would be incurred and they may be subject to change. At this time, McElroy's Run is not expected to close for at least another seven years, and could stretch out additional years depending on how much coal ash and scrubber sludge is added in future years. Second, including the potential future costs associated with closing the McElroy's Run coal ash impoundment would not have affected the outcome of the RFP given the timing of those costs. Any

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4 *See Southwestern Electric Power Co., et al. v. EPA*, No. 15-60821 (appeal docketed Nov. 20, 2015).

5 *EPA to Reconsider ELG Rule*, EPA.gov (Apr. 13, 2017). https://www.epa.gov/newsreleases/epa-reconsider-elg-rule.

impoundment closure during the 15-year analysis period would occur after the first five year period and due to discounting, have a relatively smaller impact on NPV than costs incurred in earlier years.

Q. What is your response to Ms. Medine's claim that the RFP should have considered potential plant decommissioning costs (and replacement capacity)?

A. I disagree, for the reasons I've identified in the context of Mr. Gabel's "full life cycle" arguments above. In a more general sense, potential decommissioning costs were not relevant to the NPV analysis because none of the plants evaluated was projected to retire during the 15-year customer impact period. Even if CRA had utilized a 20-year customer impact period rather than a 15-year evaluation period, decommissioning costs still would not have been relevant to the analysis because none of the plants evaluated were projected to retire within 20 years. The same logic applies to the costs of replacement capacity. Because none of the plants are projected to retire during the customer impact period, there would be no basis for modeling the costs of replacement capacity. The RFP and CRA's evaluation methodology were consistent with industry standards and prior RFPs, which in my experience do not necessarily evaluate decommissioning costs and replacement capacity costs projected to occur outside of the finite customer impact period used in the NPV analysis. Finally, it is worth noting that any asset acquisition would eventually result in decommissioning costs. Such potential costs are not unique to Pleasants or any other generator.

Q. Ms. Medine and Mr. Schlissel contend that recent transactions involving coal-fired facilities suggest that the AE Supply offer price for Pleasants is too high. How do you respond to these contentions?

A. Ms. Medine argues (pp. 18-19) that the \$150/kW purchase price for the Pleasants Facility is "extremely advantageous to FE compared to the likely alternatives" and that "given the market for power generation, it is unlikely that AE Supply would receive a bid anywhere close to what the Company has agreed to pay." She takes this position because other coal generation capacity in PJM recently sold for less (\$68/kW). Mr. Schlissel offers similar testimony (pp. 68-69). Although these claims go somewhat beyond the scope of CRA's role in the RFP, I reject the notion that a purchase price developed in a competitive market process like an RFP should be undermined by reference to transactions involving different facilities, at a different time, by different purchasers. First, nobody could reasonably suggest that identifying a single, purportedly similar, transaction for a different facility is a more effective means of determining a market price than a competitive solicitation process. If simply identifying one similar transaction was an equally or more effective means of establishing a market price than an RFP, it is hard to imagine the Commission or any market participants would support the use of RFPs given their cost and the time needed to design, administer, and score them. Second, if considering other sale transactions were an appropriate means to determine market value, then certainly a recent sale of the same asset would be much more informative than the sale of a different generating unit located elsewhere; I understand that the Commission

approved Mon Power's sale of its minority interest in Pleasants for $733/kw less than four years ago (see Petition at p. 6.). In sum, while I am not personally familiar with the unrelated transaction and generation facilities Ms. Medine references. As someone with extensive experience designing and administering competitive solicitations in the utility industry, I believe that the referenced transaction is simply not instructive.

Q. What are Intervenors' claims regarding the "consolidat[ion] of bids" and CRA's failure to expand RFP eligibility to non-APS zone resource?

A. Ms. Medine alleges (p. 28) that "it could be argued that CRA received only two conforming bids as CRA needed to combine two of the bids to equal the capacity of Pleasants. This is simply incorrect. First, CRA did not consolidate two of the three bids into a single bid. Three conforming bids were submitted by three separate companies for three separate generation facilities. (Two non-conforming bids were submitted by two parties.) At no time did any of those respondents submit any combined or joint bid for CRA to evaluate. The relevant RFP provision CAD is relying on allowed CRA to consider non-APS zone resources if "[the RFP] does not receive at least three qualified bids." Capacity RFP at 11-12, § 4.1.2.2. However, this provision was never triggered because the RFP unquestionably received three conforming bids. A unilateral CRA decision to combine two bids into one would have been entirely baseless and unwarranted under the RFP design. Second, the RFP sought up to 1,300 MW of generation capacity, but contemplated that bids of different size generation facilities would be submitted (*i.e.*, minimum 100 MW

threshold). The RFP did not obligate Mon Power to procure the *entire* projected capacity shortfall, nor did it prevent Mon Power from purchasing one or multiple smaller facilities, one large facility, or no facilities. Ms. Medine's claim that CRA should have combined two of the three conforming bids into a single bid is simply wrong.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

Case No. 17-0296-E-PC

MONONGAHELA POWER COMPANY and
THE POTOMAC EDISON COMPANY

Petition for Approval of a Generation Resource
Transaction and Related Relief

REBUTTAL TESTIMONY OF
THOMAS SWEET

September 18, 2017

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Thomas Sweet, and my business address is 400 Perimeter Center Terrace, Suite 500, Atlanta, GA 30346. I provided Direct Testimony on March 7, 2017 on behalf of Monongahela Power Company ("Mon Power") and The Potomac Edison Company ("PE," and together with Mon Power, the "Companies").

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the direct testimony of David Schlissel on behalf of WVSUN/CAG, Emily Medine on behalf of CAD and Tyler Comings on behalf of the Sierra Club. In summary, I disagree with Mr. Schlissel's contentions (i) that forward prices are a reasonable basis on which to forecast long term natural gas and energy prices and (ii) that natural gas, energy, and capacity prices in the PJM-APS Zone are likely to remain low in the foreseeable future. I also disagree with Ms. Medine's criticism of ABB's determination of basis differentials between Henry Hub and APS Zone natural gas prices. In addition, I disagree with Mr. Comings' contentions that (i) ABB's forecasted natural gas prices are flawed because they break with historical trends, (ii) ABB's forecasted 2017 energy prices were 6% higher than average hourly prices; and (iii) ABB's forecast of capacity prices is outdated and inflated.

I will also offer a general response to suggestions by various intervenor witnesses, including the Citizens Action Group, Consumer Advocate, and others that PJM energy and capacity prices are likely to remain low for the foreseeable future. I will explain that in addition to states taking actions to address policy initiatives such as Renewable Energy

Credits, Demand Response, Energy Efficiency and generation, there are changes proposed to occur at PJM and the Federal Energy Regulatory Commission that, if adopted, may result in changes in the wholesale energy and capacity prices and/or could increase value for coal-fired generation.

I. <u>ABB's Natural Gas Price Forecasts</u>

Q. MR. SCHLISSEL TESTIFIES (pp. 26-27) THAT "[C]URRENT NATURAL GAS FUTURES PRICES (WHICH REPRESENT THE MARKET'S VIEW OF FUTURE NATURAL GAS PRICES) REFLECT THE MARKET'S EXPECTATION THAT GAS PRICES WILL REMAIN LOW IN COMING YEARS." ARE NATURAL GAS FUTURES PRICES A GOOD INDICATOR OF LONG TERM FORECAST OF NATURAL GAS PRICES?

A. No. Futures prices represent the price at which natural gas can be transacted today to be delivered in the future. Futures contracts are primarily a hedge against future price volatility, not a measure of price expectations. Futures contracts for the NYMEX Henry Hub are intended to enable transactions that are part of broader risk management strategies. They are purchased or sold by entities that buy and sell commodities as part of price hedging strategies to manage price risk. Futures contracts are also bought and sold by speculators to generate a profit while assuming the price risk.

Although the NYMEX Henry Hub strip has been demonstrated to have use as a predictor of near-term future spot prices, it has very limited long-term predictive value. After 24 months, the trading volume on the NYMEX Henry Hub strip declines to nearly

zero, yielding very little, if any, meaningful price information and thus little insight into the natural gas market beyond that period. Therefore, while futures are often used as a measure of price expectations, research indicates that beyond a 24-month window, forward prices are no better at predicting the future than randomly generated ones. For example, in 2008, the NYMEX Henry Hub forward price for 2017 averaged \$9.30/MMBtu. Both prompt month NYMEX futures and ICE Day Ahead prices have averaged around \$3.05/MMBtu and ranged from \$2.50/MMBtu to \$3.45/MMBtu in 2017.

Q. DO YOU EXPECT NATURAL GAS PRICES TO REMAIN AS LOW AS THEY ARE NOW IN THE COMING YEARS?

A. No. I therefore disagree with Mr. Schlissel's assessment (pp. 33-34) that natural gas prices can be expected to remain low for the foreseeable future. ABB utilizes data from Rystad Energy for its fundamentals-driven natural gas price forecast. ABB's analyses of production based on forward prices for natural gas show that, using a price trajectory based on Forward prices, U.S. gas production would grow from 74 Bcfd in 2017 to 75.7 Bcfd in 2018 then fall in every year to 53.5 Bcfd in 2025 and continue to fall thereafter. Most demand growth forecasts (where exports are included) indicate demand growth for natural gas.

This underlines the point that current prices are not high enough to sustain growth in overall natural gas production in the long run. Sustained growth in production would need to be predicated not only on gas produced in the cheapest and most productive shale

plays, which indeed can produce significant quantities of gas at low cost ($2/MMBtu-$3/MMBtu), but also on gas produced in the higher cost portions of these low-cost plays and other areas more marginal plays, which are significantly higher cost

Additionally, there are over 120 companies in the U.S. Oil and Gas Exploration & Production (U.S. E&P) sector that have filed for bankruptcy since January 2015. This accounts for almost $80 billion in cumulative debt. U.S. E&P balance sheets also reflect that the current period of unsustainable low prices has produced significant periods of negative cash flow for many more producers. It is true that some producers are performing well financially due to their acreage holdings, lower technology costs, and a focused approach on the most productive portions of their holdings. In the near future, however, these higher intensity techniques will most likely see diminishing returns to scale; although they have contributed, in part, to lower production costs for shale gas, they are likely to have limited impact on lowering costs in the future.

Q. MR. SCHLISSEL TESTIFIES (p. 31) THAT "FUTURES PRICES HAVE GENERALLY BEEN DECLINING SINCE THE FALL OF 2014," AND THAT "THE GENERAL EXPECTATION OF THE MARKET THAT GAS PRICES WILL REMAIN LOW, WITH LITTLE ESCALATION, HAS REMAINED THE SAME." DO YOU EXPECT LONG-TERM NATURAL GAS PRICES TO FOLLOW THE RECENT HISTORICAL TREND (I.E., FUTURES PRICES HAVE GENERALLY BEEN DECLINING SINCE THE FALL OF 2014)?

A. No. As I discussed above, futures prices cannot be utilized to estimate the long-term trend in natural gas prices. ABB's fundamentals-driven natural gas price forecast is intended to be a forecast of future prices, has a known set of inputs, and incorporates quantifiable inputs reflective of long-term fundamental market factors in addition to the short-term NYMEX Henry Hub strip. It is formulated from detailed fundamental-based modeling of the fuel and electric power system. With a fundamental forecast, the inputs are known and quantifiable and therefore the impact of changes to inputs can be quantified in the results.

Q. MR. COMINGS TESTIFIES (p. 26) THAT "ABB's FORECAST OF ENERGY PRICES SHOWS A MARKED INCREASE IN PRICES, DUE IN PART TO AN ASSUMPTION OF A SHARP NATURAL GAS PRICE INCREASE IN THE FUTURE [THAT] PORTENDS A BREAK FROM THIS TREND [OF DECREASING NATURAL GAS PRICES]." DOES A BREAK FROM THE HISTORIC TREND OF DECLINING GAS FORECASTS SIGNIFY A FLAW WITH ABB'S GAS PRICE FORECAST?

A. No. As I explained in responding to Mr. Schlissel's testimony, gas prices will not remain low in the coming years because demand for natural gas is expected to grow, and current low prices are insufficient to sustain growth in overall natural gas production in the long run. Natural gas prices must go up. Mr. Comings' focus on historical trends ignores the need in forecasting to account for potential changes in demand-side and supply-side drivers.

Q. MR. SCHLISSEL TESTIFIES (p. 28) THAT "ABB'S PROJECTIONS OF FUTURE NATURAL GAS PRICES [HAVE] CHANGED SIGNIFICANTLY OVER TIME." DO CHANGES IN ABB'S PROJECTION OF LONG-TERM NATURAL GAS PRICES OVER TIME CREATE ANY INCONSISTENCIES OR OTHERWISE MAKE ITS PROJECTIONS LESS RELIABLE OR USEFUL?

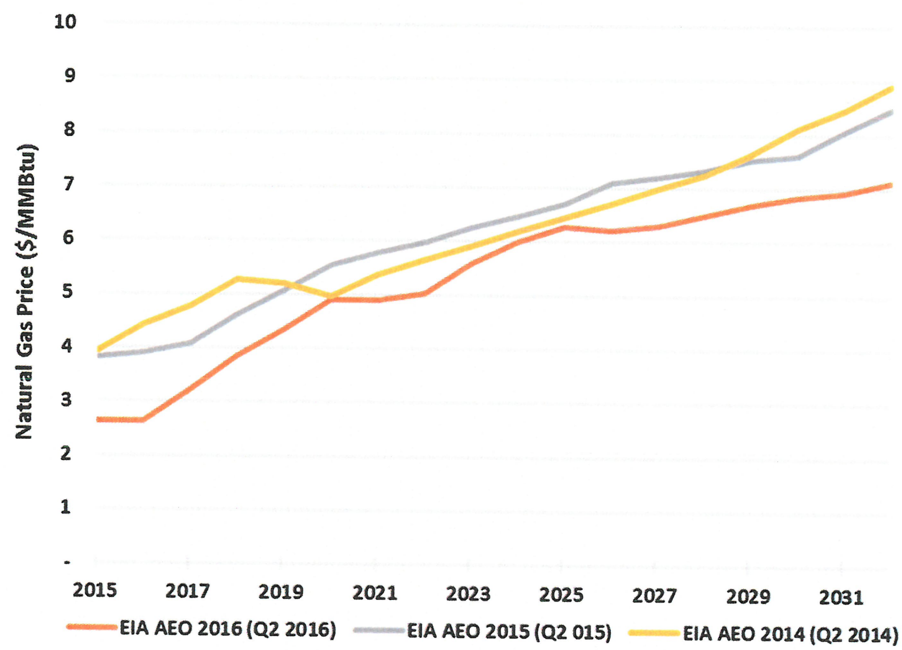
A. No. While ABB's projection of long-term natural gas prices changes over time based on changes in underlying fundamental drivers related to supply and demand, these changes over time do not create inconsistencies that impair the value of the projections. ABB updates its fundamentals-driven projection of long-term natural gas prices over time as

market information evolves. When changes in underlying assumptions such as shale gas production and its impact on the gas infrastructure occur, ABB incorporates relevant market information in the development of its long term natural gas price forecast. Indeed, as the fundamentals and underlying assumptions are always changing, changes in long-term price forecasts over time are exactly what one would expect to see. Conversely, a situation in which long-term price forecasts were not adjusted over time would itself reflect unreliability.

Q. HAVE YOU COMPARED YOUR NATURAL GAS PRICE FORECAST WITH OTHER SOURCES?

A. Yes. ABB's natural gas price forecast has been more or less similar to those published by the Energy Information Administration (EIA) for the past several years. Refer to Figure 1 for a comparison of EIA natural gas forecasts for 2014 through 2016.

Figure 1 – Comparison of EIA's 2014 to 2016 natural gas forecast



These recent changes reflect an industry-wide assimilation of information on changing contributing factors including market conditions, technology, productivity, and other industry adaptations affecting shale oil and gas production costs and therefore prices over time. Nevertheless, significant changes such as adverse and unpredictable weather conditions (i.e. hurricane Katrina resulting in high natural gas prices in 2005), persistent low economic activity along with heavy penetration of renewable resources in a short period of time would have a material impact on natural gas prices and therefore, natural gas prices may not sustain at current levels.

Q. MS. MEDINE TESTIFIES (pp. 47-48) THAT ABB'S NATURAL GAS FORECASTS "SHOW[] SIGNIFICANT AND QUESTIONABLE NEGATIVE BASIS DIFFERENTIALS FOR GAS SOLD IN THE APS ZONE THROUGHOUT THE FORECAST PERIOD." DO YOU AGREE?

A. No. ABB's incorporation of underlying fundamental drivers results in appropriate basis differentials for gas sold in the APS zone. The breakeven production cost of Marcellus and Utica gas is significantly lower than the breakeven costs for much of the shale gas that supplies Henry Hub. This lower breakeven production cost enables Appalachian producers to continue to add more production even as they sell their gas at significant discounts to Henry Hub. Also, much of that gas is constrained to where it can be used due to lack of gas transportation infrastructure. Therefore, it is perfectly reasonable to expect that gas price hubs in the producing areas of Marcellus and Utica will see significant discounts versus Henry Hub. This is especially true considering the expectations for Marcellus and Utica to grow beyond the ability of the current expansion of gas transmission capacity out of the Appalachian region by the late 2020s, necessitating even more additional investment in gas transmission infrastructure at additional cost.

Q. DOES ABB CONSIDER GAS INFRASTRUCTURE PROJECTS IN THE DEVELOPMENT OF ITS NATURAL GAS PRICE FORECAST?

A. Yes. ABB considers the size, location, lead time, etc., related to gas infrastructure projects in the development of its natural gas price forecast. ABB reviews not just the

gas transmission infrastructure projects pipeline but also construction costs associated with these projects. High construction costs translate to transportation costs, reducing the ability of gas producers to receive a premium for their gas at the receipt point. For example, tariffs on the Atlantic coast pipeline have a reservation rate of more than \$1.50/MMBtu, and more than \$1.00/MMBtu for Rover Pipeline. Reservation rates are the portion of a natural gas transmission tariff which purchasers of firm delivery capacity on interstate natural gas pipelines pay to hold capacity on a pipeline. In other words, it is the "rent" shippers pay to make sure they have access to ship gas on a pipeline. Reservation rates are a fixed cost component and generally constitute between 60% to 90% of the cost of moving gas on a pipeline. Variable costs, including commodity or per unit rates, transmission fuel and other charges, constitute the remainder. These rates are indicative of what the cost to move gas away from the Marcellus region will be on new infrastructure projects and drive a significant portion of the negative basis differential between Appalachian supply hubs and Henry Hub.

II. ABB's Energy Price Forecasts

Q. MR. SCHLISSEL TESTIFIES (pp. 36-37) THAT "CURRENT FORWARD PRICE CURVES SUGGEST [ENERGY MARKET PRICES] WILL REMAIN LOW FOR THE COMING YEARS." ARE FORWARD ENERGY MARKET PRICE CURVES A GOOD PREDICTOR OF LONG-TERM ENERGY PRICES?

A. No. As with natural gas prices, the trading volume and liquidity of energy market forward price curves decline drastically in the long term, and therefore do not provide reliable insight into the price movements of the energy market.

Q. MR. SCHLISSEL TESTIFIES (p. 38) THAT "THE AVERAGE ANNUAL [ENERGY MARKET PRICES] FORECAST[ED] BY ABB RISE CONSIDERABLY IN COMING YEARS, FAR ABOVE WHAT THE RECENT [ENERGY MARKET PRICES] AND CURRENT FORWARD ENERGY MARKET PRICES SUGGEST ARE REASONABLE TO EXPECT." DO YOU AGREE?

A. No. Mr. Schlissel's apparent reliance on trending recently settled values is a simplistic approach and does not account with any degree of certainty for changes in various demand-side and supply-side drivers that ultimately drive energy prices. It is more appropriate to use fundamental demand-side and supply-side drivers as they incorporate quantifiable inputs reflective of long-term fundamental market factors in addition to short-term market movements.

Q. MR. COMINGS TESTIFIES (p. 27) THAT ABB'S FORECASTED ENERGY PRICES FOR 2017 WERE 6 PERCENT HIGHER THAN THE ACTUAL AVERAGE HOURLY PRICES. DO YOU AGREE?

A. No. Mr. Comings claims he compared ABB's forecasted 2017 energy prices to actual average hourly prices using PJM day-ahead LMPs for Pleasants through July 2017. However, an analysis of average hourly prices from January 2017 to July 2017 for the APS price node results in an around the clock price of $29.28/MWh, which is close to the $29.50/MWh projected by ABB in its Spring 2016 Midwest Reference Case. The only comparison I have identified which shows ABB's forecasted 2017 energy prices to be 6 percent higher than actual average hourly prices for the APS node is an analysis limited to on-peak (daytime) prices. The January 2017 to July 2017 on-peak prices from ABB's Spring 2016 Midwest Reference Case ($35.23/MWh) is 6 percent higher than the on-peak prices for APS price node in the same time period ($33.17/MWh). However, such a comparison of a subset of hourly prices does not support Mr. Comings' broader statement.

Q. MR. SCHLISSEL CONTENDS (pp. 38-40) THAT ABB'S FORECASTS OF FUTURE ENERGY MARKET PRICES HAVE CHANGED SIGNIFICANTLY IN RECENT YEARS. PLEASE EXPLAIN WHY ABB'S FORECAST OF ENERGY PRICES CHANGES OVER TIME.

A. Changes in ABB's forecast of energy prices are in response to the underlying fundamentals of demand and supply. ABB's energy price forecast incorporates demand

and supply fundamentals in addition to short-term market changes. For example, the energy price forecasts for PJM-APS from ABB's Spring 2016 Midwest Reference Case reflect the changes in market developments, both short-term and long-term. These include changes in fuel prices, growth of distributed generation resources, energy efficiency, load, generator retirements and/or additions, etc. As natural gas units typically set the market clearing price in PJM-APS, energy prices follow the trajectory of natural gas prices. Therefore, changes in the natural gas price forecast outlook is the primary driver for changes in ABB's energy price forecast in the PJM-APS market.

III. <u>ABB's Capacity Price Forecasts</u>

Q. MR. SCHLISSEL PREDICTS (pp. 54-55) THAT CAPACITY PRICES WILL STAY RELATIVELY LOW FOR THE FORESEEABLE FUTURE BECAUSE THE MAY 2017 AUCTION FOR THE 2020/2021 DELIVERY YEAR ACQUIRED ENOUGH CAPACITY AND APPROXIMATELY 16,000 MW OF CAPACITY FAILED TO CLEAR, WHILE PJM LOADS REMAIN STAGNANT. DO YOU EXPECT PJM CAPACITY PRICES TO REMAIN LOW IN THE FUTURE?

A. No. Capacity prices change in response to fundamental changes in peak demand, availability of generators, unit retirements due to economics or age, reserve margin requirements, and related factors. In ABB's Spring 2016 Midwest Reference Case, for example, peak demand increases in 2020 in comparison to 2019 (a 3.3% year-over-year increase), and over 500 MW of existing capacity retires between 2020 to 2021. These factors result in tighter reserve margins and consequently higher capacity prices. The

higher capacity prices will incentivize the addition of new resources and relax the reserve margin. Therefore, it is not surprising that capacity prices are higher in the 2020-2021 time period in comparison to 2019 in ABB's Spring 2016 Midwest Reference Case. From 2021 to 2040 peak demand continues to increase at an approximate 0.6% annual rate and approximately 730 MW of existing fossil fueled capacity retires annually. These factors keep capacity price high. Moreover, these factors do not suggest that capacity prices are likely to remain low on a long-term basis.

Q. MR. COMINGS TESTIFIES (p. 22) THAT "ABB'S FORECAST OF CAPACITY PRICES IS OUTDATED AND INFLATED." DO YOU AGREE WITH THIS CHARACTERIZATION OF ABB'S FORECAST OF CAPACITY PRICES?

A. No. While ABB's forecast for 2020/2021 was higher, the long-term capacity price forecast was driven by demand and supply fundamentals in the Spring 2016 Midwest Reference Case. Historically, the PJM region has had higher reserve margins due to surplus capacity and that has resulted in lower capacity prices. In the long run, as supply tightens due to unit retirements and load growth, reserve margins decrease and consequently, capacity prices increase.

Q. MR. COMINGS TESTIFIES (p. 22) THAT "A MORE REASONABLE FORECAST OF CAPACITY PRICES [IS] BASED ON THE AVERAGE RELATIONSHIP BETWEEN THE CLEARING PRICE AND NET CONE." DO YOU AGREE WITH MR. COMINGS' METHODOLOGY FOR FORECASTING CAPACITY PRICES?

A. No. I do not agree with Mr. Comings' methodology for forecasting capacity prices in the long-term. It is a simplistic approach based on historical trends. It does not account for potential changes in demand-side and supply-side drivers. These drivers ultimately affect capacity prices in the long run. Further, historical prices are typically not indicative of future projections for capacity prices because capacity prices are driven by changes in fundamentals of supply and demand.

IV. Policy Changes That Could Impact Prices

Q. WHAT POTENTIAL MARKET STRUCTURE REFORMATIONS ARE BEING DISCUSSED AT FERC THAT COULD AFFECT HOW GENERATION IS COMPENSATED IN PJM, AND WHAT OTHER ACTIONS HAVE STATES TAKEN?

A. PJM is considering both capacity and energy market design changes. This has included a PJM Capacity Construct and Public Policy Senior Task Force contemplating capacity market reforms; a filing by PJM at FERC requesting guidance and direction on energy price formation rules to recognize the contribution of all resources, including baseload resources, in serving load; and comments filed by PJM at FERC requesting guidance on incorporating state programs into markets.

FERC has been evaluating potential future market reforms. This has included a Technical Conference on incorporating state public policies into wholesale energy and capacity markets and a Notice of Proposed Rulemaking on accommodating Electric Storage Resources into wholesale markets. Additionally, the changeover in FERC commissioners has resulted in new viewpoints being offered on some of these issues.

In addition to taking action on policy initiatives such as Renewable Energy Credits, Demand Response and Energy Efficiency, some states with nuclear power plants have adopted or are considering Zero Emissions Credit ("ZEC") legislation which compensates nuclear power plant production for the economic, environmental and fuel diversity benefits nuclear power provides. Both Illinois and New York have enacted ZEC legislation, similar legislation is pending in Ohio on this subject, and the General Assembly and Governor's administration in Connecticut has recently announced forthcoming bipartisan legislation to address similar issues. Those incentives will help insure that nuclear power plants do not close and continue to provide baseload generation. These examples, and other state driven policy initiatives are currently being considered for integration into the wholesale markets by PJM, FERC and industry stakeholders.

Q. WHAT EFFORTS ARE AFOOT AT THE UNITED STATES DEPARTMENT OF ENERGY ("DOE") RELATED TO COMPENSATION FOR BASELOAD GENERATION?

A. The DOE recently completed and issued an Electric Grid study in August 2017 that reviewed the expected impact of premature retirement of baseload generation to system resiliency. The study raises concerns regarding the compensation that market structures provide for the electric grid. The report suggests that FERC should expedite its ongoing efforts with states, RTO/ISOs, and impacted stakeholders to improve energy price formation, and to study and make recommendations on regulatory mechanisms to compensate grid participants for services necessary to support reliable grid operations. The study also suggests that the DOE and other federal agencies accelerate and reduce costs for licensing, relicensing, and permitting of grid infrastructure like nuclear, hydro, and coal generation assets.

Q. ARE ANY OF THESE PJM, FERC, OR STATE EFFORTS CERTAIN AT THIS POINT?

A. No. However, these evolving efforts and the resulting market uncertainty they may have on future forecasts should be monitored, and if and when any are adopted, should be used in evaluating the energy and capacity prices in PJM. To clarify further, these efforts were unknown during and after ABB's Spring 2016 Midwest Reference Case was published, and therefore, uncertainty associated with these efforts was not reflected in the forecast prices.

Q. ARE YOU AWARE OF WEST VIRGINIA GOVERNOR JIM JUSTICE'S COAL INFRASTRUCTURE PLAN TO PROTECT THE ELECTRIC POWER GRID IN THE EASTERN U.S. COAL FIELDS?

A. Yes. While the plan still appears to be in a development stage, I understand that Governor Justice has presented his plan to President Donald Trump that calls for $4.5 billion annually in federal funding to power companies that burn steam coal mined in Northern and Central Appalachia. The incentive would guarantee that Eastern coal would be available to keep the power grid up and operational in the event of any type of emergency shutdown that would impact power plants. As described, this homeland security incentive would protect the eastern power grid by utilizing a $15 per ton support for coal jobs to power utilities to create coal jobs in West Virginia and the surrounding area. The Governor has publicly noted that incentives for the eastern coalfields are necessary for a variety of reasons and that they may not be able to survive another economic downturn. The Governor also has indicated that he believes the country is becoming too reliant on natural gas for power and that this assistance is a matter of natural security.

Q. ARE YOU AWARE OF THE PROPOSED GAS TRANSMISSION PIPELINES AWAITING APPROVAL AT FERC IN THE WEST VIRGINIA AND SURROUNDING AREAS AND WHAT THE EFFECT ON NATURAL GAS PRICES MAY BE IN THE WEST VIRGINIA (MARCELLUS) AREA ONCE CONSTRUCTION IS COMPLETED?

A. Yes, much of the gas in that area of north-central West Virginia and south-eastern Pennsylvania is currently constrained due to lack of gas infrastructure to move the produced gas to markets in the surrounding region for consumption and for Liquid Natural Gas ("LNG") export. As I have previously discussed, once those pipelines are in place --- for which there are nine (9) new transmission lines proposed for West Virginia including the Atlantic Coast pipeline, the Mountain Valley pipeline, the Western Marcellus pipeline, the Leach XPress, Access South pipeline, and the Rover pipeline --- there will likely be upward pressure on the pricing for natural gas as the oversupply of gas in the area is depleted due to the new transmission pipelines.

Q. PLEASE SUMMARIZE YOUR POSITION ON THESE ACTIVITIES AND INITIATIVES THAT MAY IMPACT MARKET PRICES.

A. It is not that simple to say, as some of the intervenors have done, that energy and capacity prices are likely to remain low for the foreseeable future. Energy prices have always been volatile and changing. The activities and initiatives that I summarize above create uncertainty and potential volatility in the future of energy and capacity prices. The adoption of any or all of these initiatives will likely affect energy, capacity or natural gas

price projections; however, the timing and magnitude related to any change in price projections are unknown at this time. Whether it is hurricanes, restrictions on fracking, government initiatives like the ones I describe above, or the many other factors that can and do affect energy pricing, I believe that energy prices will continue to remain uncertain and volatile.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

Case No. 17-0296-E-PC

MONONGAHELA POWER COMPANY and
THE POTOMAC EDISON COMPANY

Petition for Approval of a Generation Resource
Transaction and Related Relief

REBUTTAL TESTIMONY OF

KURT P. LEUTHEUSER

September 18, 2017

Q. Please state your name and business address.

A. My name is Kurt P. Leutheuser and my business address is 3550 Green Court, Ann Arbor, MI 48105-1579.

Q. By whom are you employed and in what capacity?

A. I am employed by Black & Veatch and my title is Project Manager. My employment is devoted to the operation of executing power related projects at Black & Veatch.

Q. Are you the same Kurt Leutheuser who previously provided testimony in this proceeding?

A. Yes. I provided Direct Testimony on March 7, 2017 on behalf of Monongahela Power Company ("Mon Power") and The Potomac Edison Company ("PE," and together with Mon Power, the "Companies").

Q. What is the purpose of your rebuttal testimony?

A. I will address claims by Nikhil Kumar and Thomas Burnett, witnesses for Longview Power, LLC ("Longview") that Pleasants is an inadequate generating asset. I will also support the review of Allegheny Energy Supply Company, LLC's proposal conducted by Black & Veatch and the conclusions summarized in its report dated February 28, 2017.

Q. Mr. Burnett stated on page 8 of his direct testimony that "[t]here is not sufficient information to describe the plant as a modern well maintained plant." Do you agree with this characterization?

A. No, I do not. I would first like to point out that Mr. Burnett uses "modern" and "modernized" interchangeably throughout his testimony in his characterization of the

plant. As Mr. Burnett notes, the Companies' witness Jay Ruberto actually described Pleasants as "well maintained" and "thoroughly modernized."[1]

I believe Pleasants is a well-maintained, modernized plant. As stated in our report in section 3.2, the facility employs condition monitoring as part of its Reliability Centered Maintenance (RCM) Program. Regular inspection and maintenance of the major plant components are performed in a manner that is consistent with good practice for this type of facility. We did not find anything in the data we reviewed during the study nor in the testimony filed by others that would indicate continued operation is not practical.

Most of the plant components are of current designs and the control and air quality control systems have been modernized. The plant has also undergone a number of upgrades to systems as identified in section 3.5.2 of our report, indicating that issues are resolved as they arise.

Q. Several opposing witnesses note that the plant is 38 years old. Does this mean that Pleasants cannot operate reliably for decades?

A. No. As stated in the report and repeated in my direct testimony "it is possible through normal maintenance to operate longer than that depending on the robustness of the original design and the effectiveness of the operation and maintenance practices of the plant throughout its life."

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[1] Direct Testimony of Thomas Burnett at 9:10-12.

Q. Ms. Medine stated on page 10 of her direct testimony that Black & Veatch "did not accept the 65-year life" assumed in CRA's NPV analysis. Is this correct?

A. No. Ms. Medine appears to base this assertion on a statement in our report regarding the normal design life being 40 years. The "design life" of a facility is used during the design phase of a power plant as the basis to perform NPV type analyses to evaluate equipment selections as well as the basis to make design decisions such as those relating to material selection and fatigue cycles. Well-maintained facilities are capable of operating for many years beyond their original design lives. Based on our review of Pleasants, we found that the plant has continually employed robust maintenance practices. As a result, Pleasants has few operating limitations and is therefore capable of providing reliable service for many decades to come.

Q. Do your answers to the above questions mean that you disagree with Mr. Kumar's and Mr. Burnett's assessments that inadequate investments have been made to keep Pleasants operational for another 20 years?

A. Yes, I disagree with Mr. Kumar's and Mr. Burnett's assertions that Pleasants has demonstrated a lack of investment to keep the plant operational. Section 3-10 of Black & Veatch's report lists several major projects including a new stack, new wastewater treatment facility, new SO_3 treatment system, GSU transformer replacement and miscellaneous coal mill inspections/overhauls and sootblowing air compressor overhauls. Although not explicitly discussed in the report, the Pleasants' wet flue gas desulfurization system was extensively rebuilt in 2007. All of these projects demonstrate an ongoing modernization of the plant that addresses operating problems and regulatory compliance.

Q. Do you agree with Mr. Burnett's assertion on page 10 of his testimony that there is "a high degree of uncertainty as to the ability of this plant to meet its intended operation?"

A. No. From a technical standpoint we did not identify any serious flaws in the plant design that would preclude its continued operation. As stated in our report in section 3.2, the inspection and maintenance of the major plant components are consistent with good engineering practice and represent the necessary management systems to achieve many decades of service.

Q. Why did Black & Veatch not address the risk of a high impact low probability (HILP) event, as noted on page 38 of Mr. Kumar's direct testimony?

A. While I am familiar with the term HILP, I am not aware of a standard definition. Assuming for purposes of this question that Mr. Kumar's definition of an HILP event is reasonable, Mr. Kumar's assertion that we did not address the risk of a HILP event is inaccurate. Black & Veatch's report addressed the general known causes for HILP events such as flow accelerated corrosion, monitoring of the condition of major components (boiler, turbine, etc.) and confirmed that the plant maintenance programs are in accordance with best practices. If Black & Veatch discovered major issues that could lead to such events, it would have identified them in its report. I would also note that Mr. Kumar's testimony did not correlate the probability of HILP events with specific causes, maintenance practices, or any other factor that would allow predicting if a specific attribute of the facility were susceptible to having such an event occur.

Q. Mr. Burnett on page 3 of his testimony describes several concerns with the depth and thoroughness of the Black & Veatch Report. Why do you believe the Black & Veatch Report was sufficient?

A. The Black & Veatch report provided an independent assessment of the Pleasants' proposal, focusing on the Companies' main issues of concern. Although Black & Veatch developed the report independently, the Mon Power representative that accompanied our team during the site visit was very aware of the history of the plant, and on occasion supplemented the current plant staff's explanation of the plant's history. This is to be expected since Mon Power previously owned and operated the plant. Mon Power's familiarity with the asset enabled the Black & Veatch site visit team to focus on the issues that were of concern.

Q. On pages 33-34 of his direct testimony, Mr. Burnett claims the Black & Veatch report lacks detail regarding its assessment of certain plant components. Do you agree?

A. No. First, just because something was not in the report does not mean that there was not a review or analysis undertaken by Black & Veatch. We tried to focus on the major issues and the areas that showed any level of real concern. Second, as I discuss below, Black & Veatch properly addressed these areas:

- <u>Thick Wall High Temperature Components</u>: Mr. Burnett stated a concern about detail regarding assessments of thick wall high temperature components (boiler headers, main steam and reheat piping, turbine components). Black & Veatch did review reports by Structural Integrity Associates, Inc. included in the reference

data items 31 - 33 and 37 - 39 in section 4.0. The penthouse headers and high energy piping systems for Unit 1 inspection from the spring of 2014 and the penthouse headers for Unit 2 inspection from the spring of 2016 using linear phase array ultrasonic examinations were also examined, as well as the Unit 2 turbine inspection by Siemens from the spring of 2013. Monitoring of thick wall components is appropriate for a facility of this age, but the reports mentioned above did not indicate any remarkable issues. The Black & Veatch report, in section 1.1, states that the plant is well maintained and the reports mentioned above substantiate that statement.

- <u>Coal Piping</u>: Mr. Burnett also lists concerns with coal piping, but coal pipe is a normal wear item that requires periodic rotation and replacement in any coal plant more than a few years old.
- <u>Plant Control System</u>: Mr. Burnett also stated concerns with the future needs of the plant control system, but as stated in the Black & Veatch report in section 3.12.1, the control system is an Emerson Ovation system that was updated in 2010 and is expected to be fully functional into the future. The Ovation system is a modern control system (and is actually the same control system installed at the Longview plant), and future updates would be considered a normal part of business.

In summary, most of the concerns that Mr. Burnett raises were either addressed in the Black & Veatch evaluation, or are part of the normal O&M for a power plant.

Q. Mr. Burnett asserts on page 34 of his testimony that there is no information in the Black & Veatch report regarding the review of the overall O&M costs. How was this review conducted and why wasn't data included?

A. Black & Veatch used an industry database provided by SNL Energy to screen for plant nameplate capacity and capacity factor, and compared the O&M costs for Pleasants to similar plants. Since the total O&M costs were in line with typical similar plants, this factor is not remarkable and did not require further elaboration in the report. Mr. Burnett did evaluate the breakdown in costs between the boiler plant and electric plant on page 24 of his testimony and asserts that there is a trend indicating decrease in overall maintenance spending except for the boiler plant. There are typically adjustments in annual spending depending on the need at the plant, and maintenance costs usually drop after a major outage. Considering the normal variability in annual costs, no trend is apparent to me. Black & Veatch relied on discussions with the plant engineering staff to evaluate if maintenance was being deferred or if problems were being resolved as they were found. Maintenance has been keeping up with the normal wear and tear, with the exceptions noted in the report regarding the generator and the need to improve the boiler tube procurement process for the superheater tubes.

Q. Mr. Burnett asserts on page 34 of his testimony that the Black & Veatch report should have undertaken more extensive analysis on the effects of "load following." How did the Black & Veatch report address the operation of the units?

A. As is typical of coal fired power plants in the U.S., the Pleasants station has been operating in a load following mode for many years (this is illustrated on Page 27 of Mr.

Burnett's testimony showing operation since 2001). The program that Pleasants has been conducting for the thick walled components in the boiler, high energy piping, and turbine are the industry standard methods for monitoring effects of wear and tear and correcting problems as they arise. The reliability effects of wear and tear on the unit are reflected in the EFORd rates, which are included in the Black & Veatch report.

Q. Mr. Burnett asserts on page 35 of his testimony that the Black & Veatch report did not explain or provide the reason for their findings regarding reasonable costs for operation and maintenance and the effectiveness at maintaining efficiency, reliability and availability in line with those represented. How did the Black & Veatch report address the operation and maintenance of the units?

A. The Black & Veatch report addresses the operation and maintenance of the plant in sections 3.2, 3.4, and 3.5, and these sections provide the reasoning for the findings. Section 3.2 discusses the plant's robust operation and maintenance practices, such as its Reliability Centered Maintenance Program, that will help Pleasants continue operating reliably into the future. As noted in this section, plant personnel perform regular inspection and maintenance on major components such as boilers, generators, and transformers. Section 3.4 examines current and historical operating limitations at the plant and how these issues have been addressed. Finally, Section 3.5 summarizes our review of various operating data, including annual run time hours, capacity factor, availability factor, and EFORd for both units for the past five years. This section also summarizes historical capital projects undertaken at Pleasants to improve operation.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

Case No. 17-0296-E-PC

MONONGAHELA POWER COMPANY and
THE POTOMAC EDISON COMPANY

Petition for Approval of a Generation Resource
Transaction and Related Relief

REBUTTAL TESTIMONY OF
BRADLEY D. EBERTS

September 18, 2017

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is Bradley ("Brad") D. Eberts and my business address is 76 South Main Street, Akron, Ohio 44308. I am the Manager of Load Forecasting for FirstEnergy Service Company. I provided Direct Testimony on March 7, 2017 on behalf of Monongahela Power Company ("Mon Power") and The Potomac Edison Company ("PE," and together with Mon Power, the "Companies").

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my rebuttal testimony is to respond to points in the direct testimony of Emily S. Medine on behalf of CAD, Steven Gabel on behalf of Longview, and Stephen J. Baron on behalf of WVEUG.

I. Comparisons of the Rates of Load Growth in the Companies' Forecast and Other Forecasts Are Inappropriate

Q. CAD WITNESS MEDINE TESTIFIED THAT YOUR LOAD FORECAST IS "CONTROVERSIAL IN THAT IT CALLS FOR A MUCH HIGHER LEVEL OF GROWTH THAN IS BEING FORECAST BY OTHERS AND PJM."[1] DO YOU AGREE THAT DIFFERENCES BETWEEN YOUR FORECAST AND OTHER FORECASTS MAKE YOUR FORECAST "CONTROVERSIAL?"

[1] Medine Testimony at 43:17-18. Apparently contradicting this testimony, Ms. Medine explained in response to discovery that it is "the use of the single load forecast in isolation" that is controversial, and that CAD has no objection to the Companies' load forecast being one of several forecasts considered. See CAD Responses to Companies' Requests 37 and 38, attached as Exhibit BDE-3. Ms. Medine also clarified in response to discovery that by "others" Ms. Medine means PJM. See CAD Response to Companies' Request 41, attached as Exhibit BDE-4.

A. No. To the contrary, my forecasted rate of load growth is consistent with historical rates of load growth in the Companies' West Virginia service territories. My forecast predicts a compound annual energy growth rate of 2.5% over the next 10 years. Over the last 36 years (1980 through 2016), the 10-year annual compound growth rate averaged 1.8%, with a minimum of 0.9% and a maximum of 2.7%.[2] For the period 2009 through 2016, the period after the recession, the compound annual growth rate has been 1.9%. For the same 36-year period, the average year-over-year growth rate is 1.6%, with a minimum of -6.8% and a maximum of 8.7%.

Q. DO YOU AGREE WITH MS. MEDINE'S COMPARISON OF YOUR PEAK DEMAND FORECAST TO PJM'S FORECASTS?

A. No. Ms. Medine overlooks several important differences between my peak demand forecast for the Companies and other forecasts. First, PJM's forecasts cover peak demand in different geographic areas than my peak demand forecast. My forecast is focused on load specific to the Companies' West Virginia service territories. Second, PJM's forecast for the APS zone reduced peak demand based on distributed solar generation that is located outside the Companies' service territories (i.e., in Maryland, Pennsylvania, and Virginia) and, as a result, will not reduce the Companies' peak demand. Third, PJM's forecast excludes information on economic growth within the Companies' service territories that is included in my forecast. Fourth, PJM's energy requirements forecast for the APS zone assumed energy efficiency improvements of

[2] Excludes West Virginia Power (Mon Power purchased the service territory in 1999).

appliances based upon an EIA scenario in which the Clean Power Plan is implemented, resulting in decreased energy requirements. And fifth, PJM does not use West Virginia weather stations for its APS zone forecast. All of these differences make PJM's peak demand forecast less applicable to peak demand in the Companies' West Virginia service territories and less reliable than my peak demand forecast for that purpose.

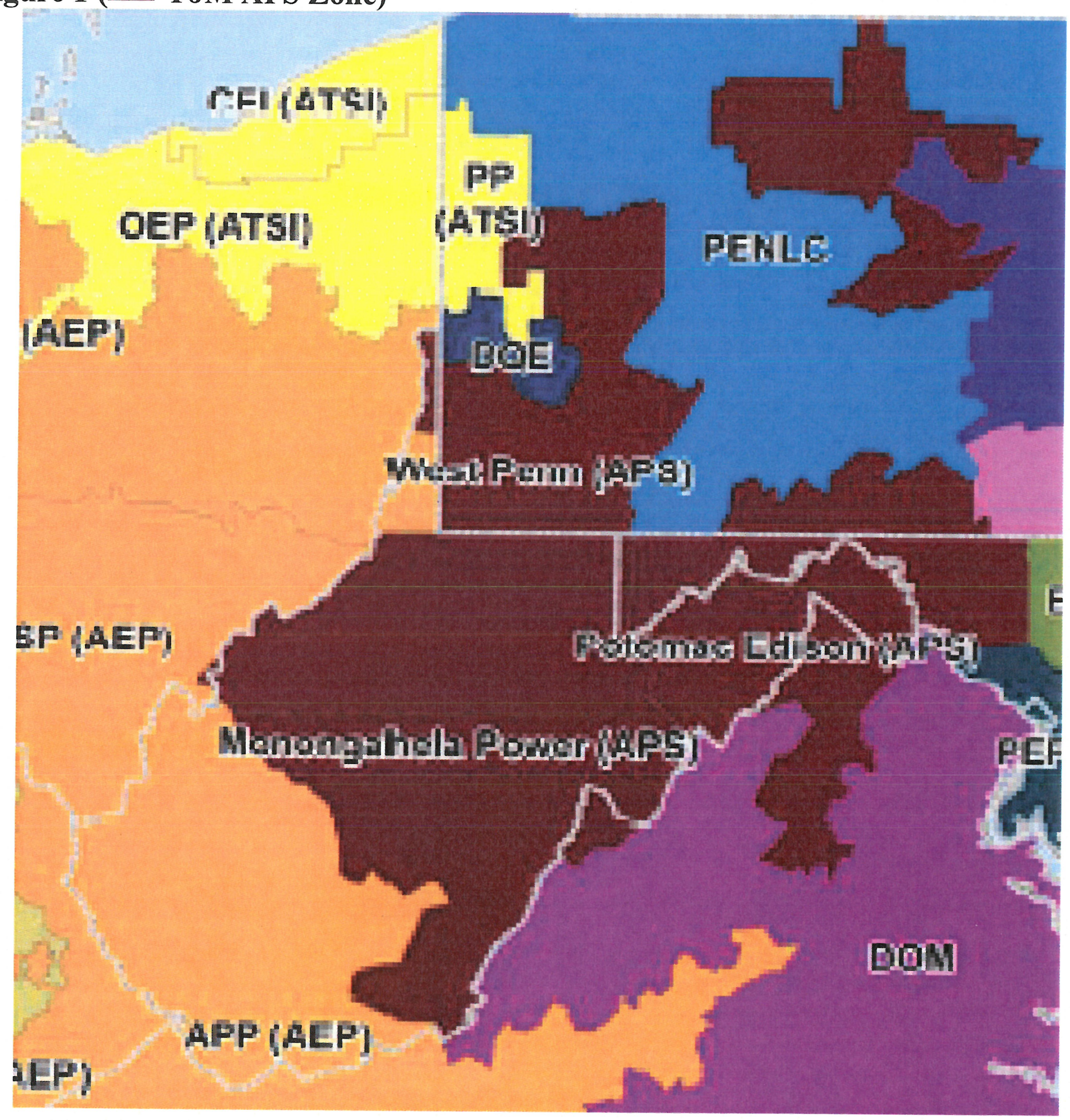
Q. PLEASE EXPLAIN HOW YOUR PEAK DEMAND FORECAST FOR THE COMPANIES COVERS DIFFERENT GEOGRAPHIC AREAS THAN PJM'S FORECAST OR OTHER FORECASTS.

A. PJM does not forecast load specific to the Companies' West Virginia service territories.[3] Rather, PJM's forecast covers load throughout the entire APS zone, which extends far beyond the Companies' service territories. While the APS zone includes part of the Companies' West Virginia load, the APS zone also includes the service territory of West Penn Power Company in Pennsylvania, PE's service territory in Maryland, and Rappahannock Electric Cooperative and Shenandoah Valley Electric Cooperative territories in Virginia. Also, a part of Mon Power's service territory is located outside the APS zone and is included in PJM's forecasts of the AEP zone. As I explained in my Direct Testimony, usage in the Companies' West Virginia territories is approximately 35% of usage in the APS zone. The geographic region of the PJM APS Zone is illustrated in Figure 1 below. As Figure 1 illustrates, the APS zone extends far beyond

[3] Further, Ms. Medine did not identify any "others" who have forecasted load specific to the Companies' West Virginia service territories.

the Companies' service territories, which are confined within the boundaries of West Virginia.

Figure 1 (▬ PJM APS Zone)



As a result, Ms. Medine's comparison of the rate of growth in my load forecast to the rate of growth in the load forecast of PJM or some "other" forecaster is inappropriate. For the same reason, Longview witness Gabel is mistaken when he testifies that "PJM's forecast

recognizes compound peak growth in the service territory of 0.3% per year."[4] In response to discovery, Mr. Gabel cited, as support for this statement, a table on page 19 of the PJM Load Forecast Report for January 2017.[5] The referenced table, however, provides the load growth rates for the various zones in PJM, including the APS zone. It does not provide a load growth rate for the Companies.[6]

Q. PLEASE EXPLAIN WHAT DISTRIBUTED SOLAR GENERATION IS AND HOW PJM ADJUSTED FORECASTED LOAD IN THE APS ZONE FOR DISTRIBUTED SOLAR GENERATION.

A. Distributed solar generation refers to the solar generation that nets directly with the load in terms of data submissions either at a customer site or via the distribution system. It is not PJM grid-interconnected, does not go through the full PJM interconnection queue process, does not offer as a capacity or energy resource, and does not provide metered production data to PJM.[7] In its January 2017 Load Forecast Report, PJM adjusted each zone's peak demand downward for distributed solar.[8] These adjustments lowered PJM's peak load forecast. In the case of the APS zone, PJM's downward adjustments start at 32 MW for 2017 and grow to 319 MW by 2031 (for a 3.5% cumulative reduction in peak

[4] Gabel Testimony at 22:1-2.
[5] See Longview Power, LLC's Responses to the Companies' First Data Request, Request No. 13, attached as Exhibit BDE-5 (directing the Companies to "[p]lease see PJM January 2017 Summer Peak Load Growth Rate Summer 2017-2027 at Page 19. Available at http://www.pjm.com/-/media/library/reports-notices/load-forecast/2017-load-forecast-report.ashx.").
[6] See PJM Load Forecast Report for January 2017, at 19, attached as Exhibit BDE-6.
[7] See *PJM Distributed Solar Generation Update*, PJM Load Analysis Subcommittee (November 18, 2016), at 4, available at http://www.pjm.com/-/media/committees-groups/subcommittees/las/20161118/20161118-item-03-pjm-distrubuted-solar-generation-forecast.ashx ("PJM Distributed Solar Generation Update").
[8] See PJM Load Forecast Report, January 2017, at 72 (Table B-8), available at http://www.pjm.com/-/media/library/reports-notices/load-forecast/2017-load-forecast-report.ashx?la=en.

demand by 2031).[9] However, the Companies' West Virginia service territories are only a portion of the APS zone, and distributed solar generation is projected by PJM to reduce the peak demand in the Companies' service territories by a much lower proportion than in the rest of the APS zone.

To adjust distributed solar generation in PJM's forecast for the APS zone to allow a fair comparison to my load forecast, one would have to determine the portion of PJM's solar adjustment for the APS zone that can be attributed to the Companies' West Virginia service territories. I calculated the Companies' portion of PJM's solar adjustment for the APS zone. Using PJM's projections of annual additions of solar nameplate capacity for the period from 2017-2031,[10] I calculated the ratio of cumulative solar nameplate capacity for the Companies to cumulative solar nameplate capacity for the APS zone. The Companies' cumulative solar nameplate capacity from 2017-2031 is 28 MW, out of 1,145 MW of cumulative solar nameplate capacity across the APS zone over the same period. As a result, the Companies' cumulative solar nameplate capacity accounts for only 2.4% of the APS zone's cumulative solar nameplate capacity. Therefore, it is reasonable to allocate 2.4% of PJM's projected 319 MW decrease in the APS zone's peak demand to the Companies. This amounts to a reduction in the Companies' peak demand of only 8 MW, which is a 0.2% cumulative reduction in the Companies' 2031 forecasted peak demand caused by distributed solar (in contrast with PJM's much larger 3.5% reduction in peak demand across the APS zone).

[9] For the entire PJM RTO, PJM distributed solar generation forecast is 4,390 MW or 2.8% of its 2031 summer peak.
[10] PJM Distributed Solar Generation Update, at 51.

In addition, the distributed solar generation adjustment has no impact on the Companies' annual peak because the Companies are winter peaking. Because the peak occurs when there is either no sunlight or minimal sunlight, distributed solar generation has no impact on winter peak demand. Indeed, PJM's distributed solar adjustment to the APS zone's winter peak is zero.[11] Further, PJM's APS zone forecast shows that by the PJM planning year 2029/2030 the entire APS zone will be winter peaking.[12] Eventually, both the Companies and the APS zone will be in a unique winter peaking situation compared to the rest of the PJM zones.

Q. MS. MEDINE TESTIFIES THAT "THE COMPANY'S PROJECTED GROWTH IS ATTRIBUTABLE TO ECONOMIC ACTIVITY RELATED TO THE EXPANSION AND UTILIZATION OF SHALE GAS, WHICH PJM ALSO CONSIDERS."[13] DO YOU AGREE THAT PJM'S FORECAST CONSIDERS THE SAME SHALE GAS-RELATED ECONOMIC ACTIVITY THAT YOUR FORECAST DOES?

A. No. PJM's Load Forecast limits, or does not include, adjustments for projected economic activities that are included in my load forecast. PJM considers adding customer specific adjustments if the adjustment is significant to the entire zone. As a result, significant additions to the Companies' territories that are not material to the entire zone are excluded from PJM's forecast. For example, PJM adjusted its 2017 Load Forecast only

[11] PJM Load Forecasting Model Whitepaper, at 60, available at http://www.pjm.com/~/media/library/reports-notices/load-forecast/2016-load-forecast-whitepaper.ashx ("There is no impact from solar treatment as the output from distributed solar generation at the time of the winter peak (typically 7:00 PM) is forecast to be 0 MW.").
[12] Page 53 (summer peak) and 58 (winter peak) http://www.pjm.com/-/media/library/reports-notices/load-forecast/2017-load-forecast-report.ashx?la=en
[13] Medine Testimony at 43:18-20.

for shale and data centers. PJM did not include two non-shale customer additions, including the Procter & Gamble plant in Martinsburg. In contrast, my forecast includes the two customers, even if they are not deemed material at the entire APS zone level, because they are adding almost 60 MW of load in PE's territory. Further, the Companies separately forecast manufacturing segments for chemical, coal, fabricated metals, food and beverage, primary metals, nonmetallic, shale gas, and wood products and furniture. PJM, however, forecasts the industrial load for the APS zone in aggregate.

The Companies' more granular approach is consistent with a focus on the West Virginia portion of the APS zone. Therefore, as I explained in my Direct Testimony, I have utilized West Virginia University's ("WVU") economic forecast. WVU's economic forecast provides more insight into important industries & areas in West Virginia, such as coal, steel, shale, chemical, and the eastern panhandle. WVU has analyzed West Virginia economics in depth and created studies for various areas of government.

By 2022, my forecast accounts for 315 MW of growth from shale customers who are projected to come online in the near future. By comparison, PJM's forecast only accounts for 250 MW from shale customers, a difference of 65 MW. In addition, from 2022 to 2031, PJM lowered its 250 MW adjustment for shale to 170 MW, a reduction of 80 MW. This 80 MW reduction effectively eliminates growth from any other economic activity from PJM's forecast after 2022. In sum, PJM's lower shale customer adjustment, combined with PJM's exclusion of four other large customer additions such as the

Procter & Gamble plant mentioned above, results in PJM adjustments which by 2031 are 219 MW lower than the adjustments I included in my more granular forecast.

Q. HOW DOES THE COMPANIES' LOAD FORECAST DIFFER FROM PJM'S WITH RESPECT TO THE CLEAN POWER PLAN?

A. In its energy requirements forecast for the APS zone, PJM assumed energy efficiency improvements of appliances based upon a variation of EIA's Annual Energy Outlook ("AEO") 2016 Reference Case in which the Clean Power Plan ("CPP") is implemented. This results in an assumption of decreased energy requirements in PJM's forecast. In contrast, the Companies' energy requirements forecast assumed energy efficiency improvements of appliances based upon a different variation of EIA's 2016 AEO reference case, in which the CPP is not implemented. By Executive Order dated March 28, 2017, the EPA was ordered to review the CPP, and "suspend, revise, or rescind" it as necessary to comply with the guidance of the executive order.[14]

The EIA's Energy Consumption by Sector and Source table shows that, in 2031, residential electricity usage would be 2.8% lower under the 2016 AEO Reference Case with CPP as compared to the 2016 AEO Reference Case without CPP. Similarly, by 2031, commercial electricity usage would be 3.3% lower under the 2016 AEO Reference case with CPP as compared to the 2016 AEO Reference Case without CPP.[15]

[14] See Executive Order dated March 28, 2017, available at https://www.whitehouse.gov/the-press-office/2017/03/28/presidential-executive-order-promoting-energy-independence-and-economi-1

[15] EIA's 2016 Annual Energy Outlook, available at https://www.eia.gov/outlooks/aeo/data/browser/#/?id=2-AEO2016&region=1-5&cases=ref2016~ref_no_cpp&start=2014&end=2031&f=A&linechart=ref2016-d032416a.3-

Q. PLEASE EXPLAIN THE DIFFERENCE IN WEATHER STATIONS USED IN PJM'S FORECAST AND IN THE COMPANIES' FORECAST.

A. As I explained in my Direct Testimony, the energy requirements and peak demand forecasts are influenced by weather. The Companies used West Virginia weather stations in Clarksburg, Beckley, and Martinsburg for their load forecast. By contrast, PJM does not use any West Virginia weather stations for its APS zone forecast. Instead, PJM used Washington Dulles and Pittsburgh International weather stations to model and forecast the entire APS Zone. Using West Virginia weather stations is important because the residential electric heating saturation for the Companies is approximately 20% higher than the residential electric heating saturation for the APS Zone. Again, the increased granularity of the Companies' approach is another reason that Ms. Medine's attempted direct comparison of the Companies' load forecasts with PJM's forecast, or other forecasts, is inappropriate.

2-AEO2016.1-5~ref_no_cpp-d032316a.3-2-AEO2016.1-5&map=ref_no_cpp-d032316a.3-2-AEO2016.1-5&sourcekey=0.

II. There Is No Reasonable Basis to Conclude That Onsite Cogeneration Will Materially Affect the Expected Growth in Production in the Companies' Service Territories

Q. DO YOU AGREE WITH WVEUG WITNESS BARON THAT THERE IS A RISK THAT A HIGHER PORTION OF THE EXPECTED GROWTH IN PRODUCTION IN THE COMPANIES' SERVICE TERRITORY WILL BE MET WITH DECENTRALIZED, MICROTURBINE GENERATORS OR OTHER ONSITE COGENERATION?"

A. No. The Companies' forecast of summer peak demand already incorporates new onsite generation growing to 8 MW by 2031. This onsite generation is from distributed solar installations. As I explained above, PJM estimated a similar amount for the Companies' territories in 2031.

The Companies keep close track of the energy needs of larger customers through the Companies' Customer Support representatives. The Customer Support representatives work closely with larger, transmission level customers to evaluate their system needs on an ongoing basis. Accordingly, the compressor station load in the Companies' forecast is based on data gathered by the Companies' Customer Support representatives, from customers who have requested to be served by Mon Power, not by onsite generation.

By contrast, Mr. Baron's testimony that there is a risk that the Companies' expected load growth will not materialize because of onsite cogeneration is based on

unknown commitments and is always a risk in serving customers. It is also based on unverifiable, anecdotal stories such as a press release about a possible microturbine installation at an unidentified remote midstream natural gas compressor station in Ohio. The story lacks important details, including whether the remote compressor station is connected to a utility's distribution system, or whether the microturbine would be installed behind-the-meter. Generation must be behind-the-meter of a customer connected to the utility's distribution system to affect the load forecast.

In addition, while Mr. Baron testified that "I am aware that onsite cogeneration . . . is being actively considered by large users in West Virginia,"[16] he explained in discovery that he has no such knowledge. Rather, he is relying on a statement from WVEUG Counsel. Mr. Baron cannot identify any of the large users by name, business type or industrial classification. Nor can Mr. Baron identify the capacity of the "onsite cogeneration" that is "being actively considered."[17] Further, Mr. Baron has done no analysis to identify any projected load loss for the Companies' service territories from 2017 through 2031 from large users' decentralized, microturbine generators or other onsite generation.[18]

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

[16] Baron Direct Testimony at 10:4-5.
[17] See WVEUG's Responses to Companies' First Data Request No. 9, attached as Exhibit BDE-7.
[18] See WVEUG's Responses to Companies' First Data Request No. 8, attached as Exhibit BDE-8.

37. Reference Medine direct, page 43, lines 12-20. Do you believe that the incorporation of Dr. Deskins' economic modeling in the Companies' load forecast renders the Companies' load forecast (i) "controversial," (ii) unreasonable, or (iii) unreliable? In each case, please explain why you believe this is so.

Response

CAD believes that a single forecast of any of the key assumptions is inappropriate. CAD believes that the use of the single load forecast in isolation is controversial, unreasonable and unreliable because of the importance of and uncertainty of the load forecast. CAD has no objection to the forecast used in the analyses sponsored by Mon Power being one of several forecasts considered.

38. Reference Medine direct, page 43, lines 12-20. Do you believe that the fact that the Companies' load forecast projects load growth in the Companies' service territory at a level that is different from PJM's forecast renders the Companies' load forecast (i) "controversial," (ii) unreasonable, or (iii) unreliable? In each case, please explain why you believe this is so.

Response

See response to 37.

41. Reference Medine direct, page 43, lines 17-18, which states that "[t]he load forecast is controversial in that it calls for a much higher level of growth than is being forecast by others and PJM."

a. Identify each one of the "others" referenced in this sentence.

b. For each one of the "others," produce every forecast you reviewed or relied upon in making this statement, including any and all inputs and outputs, equations and working spreadsheets you reviewed or relied upon in making this statement.

c. Identify each one of the "others" who prepares forecasts for West Virginia load, and produce each and every such forecast of West Virginia load you reviewed or relied upon in making this statement, including any and all inputs and outputs, equations, and working spreadsheets.

d. Identify each one of the "others" who prepares forecasts for load in the Companies' West Virginia service territory, and produce each and every such forecast of load in the Companies' West Virginia service territories you reviewed or relied upon in making this statement, including any and all inputs and outputs, equations, and working spreadsheets.

e. Does PJM prepare forecasts for West Virginia load? If so, produce each and every such forecast you reviewed or relied upon in making this statement, including any and all inputs and outputs, equations, and working spreadsheets.

f. Does PJM prepare forecasts for load in the Companies' West Virginia service territory? If so, produce each and every such forecast you reviewed or relied upon in making this statement, including any and all inputs and outputs, equations, and working spreadsheets.

g. For each load forecast produced in response to subparts (b) through (f), identify and produce the economic forecast used in developing the load forecast.

<u>Response</u>

Available PJM forecasts can be found on the PJM website. Please also see Response to 37.

LONGVIEW POWER, LLC'S RESPONSES TO
THE COMPANIES' FIRST DATA REQUEST
P.S.C. CASE NO. 17-0296-E-PC

Prepared By: Steven Gabel
President, Gabel Associates, Inc.

To Testify: Steven Gabel

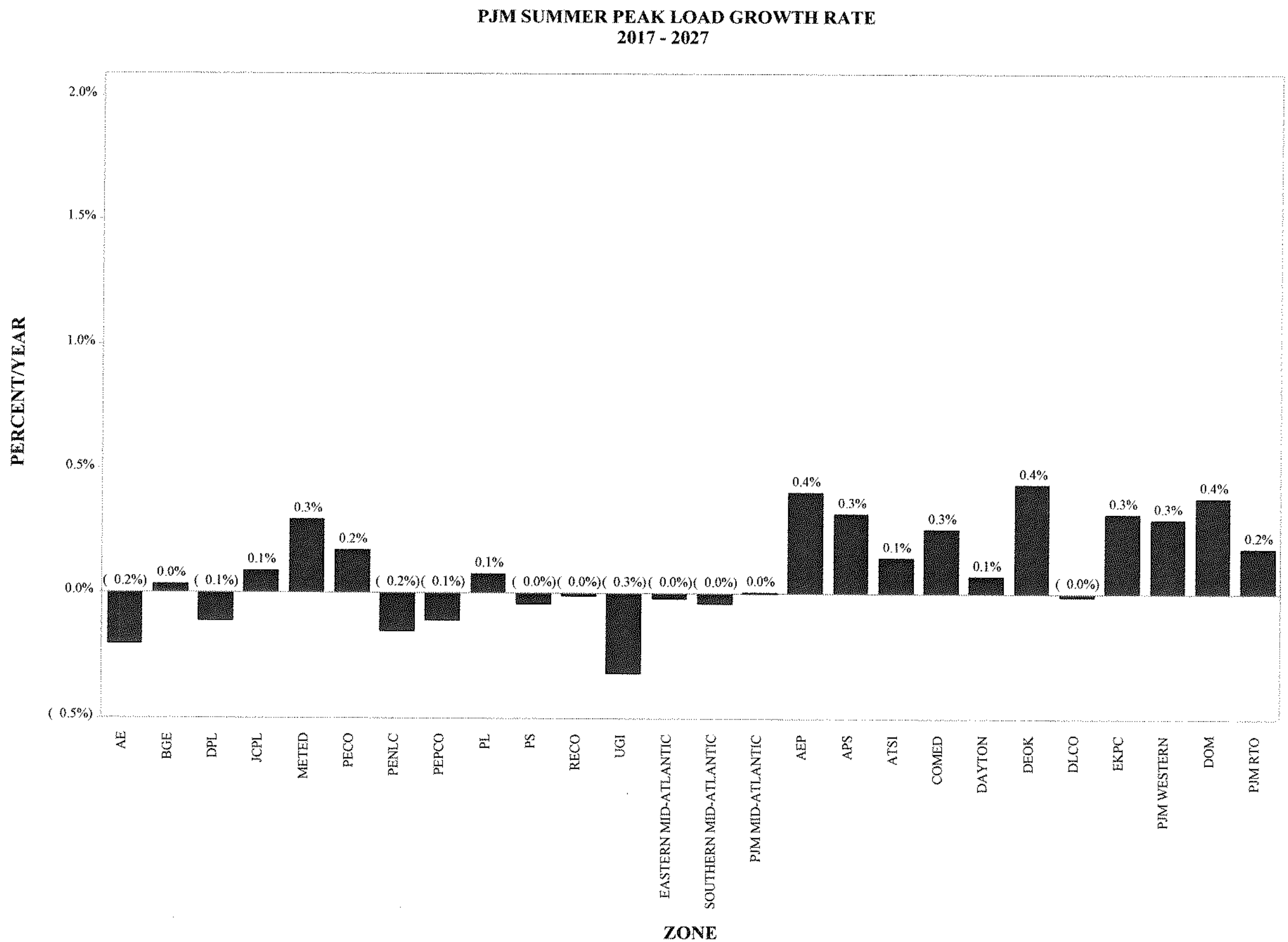
Date Prepared: September 15, 2017

REQUEST NO. 13:

Reference Gabel direct, page 22, line 1. Please provide a copy of or reference to any PJM document that substantiates your statement that compound peak load growth in the Companies' service territory is 0.3%.

RESPONSE NO. 13:

Please see PJM January 2017 Summer Peak Load Growth Rate Summer 2017-2027 at Page 19. Available at http://www.pjm.com/~/media/library/reports-notices/load-forecast/2017-load-forecast-report.ashx.


PJM SUMMER PEAK LOAD GROWTH RATE
2017 - 2027
PERCENT/YEAR
2.0%
1.5%
1.0%
0.5%
0.0%
(0.5%)
(0.2%)
0.0%
(0.1%)
0.1%
0.3%
0.2%
(0.2%)
(0.1%)
0.1%
(0.0%)
(0.0%)
(0.3%)
(0.0%)
(0.0%)
0.0%
0.4%
0.3%
0.1%
0.3%
0.1%
0.4%
(0.0%)
0.3%
0.3%
0.4%
0.2%
AE
BGE
DPL
JCPL
METED
PECO
PENLC
PEPCO
PL
PS
RECO
UGI
EASTERN MID-ATLANTIC
SOUTHERN MID-ATLANTIC
PJM MID-ATLANTIC
AEP
APS
ATSI
COMED
DAYTON
DEOK
DLCO
EKPC
PJM WESTERN
DOM
PJM RTO
ZONE

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Monongahela Power Company and The Potomac Edison Company

West Virginia Energy Users Group's ("WVEUG")
Responses to Companies' First Data Request

Question 9:

Reference Baron direct, page 10, lines 4-7.

a. Identify the source of the information on which you rely when you say you are "aware that onsite cogeneration, particularly natural gas-fired cogeneration, is being actively considered by large users in West Virginia," and produce any documents on which you rely when making this statement.

b. Identify each and every large user to which you refer in this statement.

c. For each large user identified in response to subpart (b), state whether the large user is an existing or potential customer of the Companies.

d. For each large user identified in response to subpart (b), identify the user's business type or industrial classification.

e. Explain in detail what you mean when you say "actively considered."

f. For each large user identified in response to subpart (b), identify the capacity of the "onsite cogeneration" that is "being actively considered."

g. For each large user identified in response to subpart (b), state whether the "onsite cogeneration" that is "being actively considered" will be installed behind the meter.

Response:

a. I was provided the referenced information from WVEUG Counsel, and it is consistent with my experience and expectation given the existing environment of rate increases over the last decade or more. In other words, I fully expect that large electric users like WVEUG members would be examining alternatives for power supply, including on-site generation, given that their electric rates have nearly doubled (and given the rise in availability of natural gas that can be used for cogeneration). Regardless, my point of including this reference was to identify another example of how the Companies' capacity projection might be offset. Furthermore, even if the Companies' projection proves to be correct, the full amount of capacity available from Pleasants would not be needed for many years

b. The names of the large users were not disclosed to me.

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c. **My understanding is that at least two of the large users that I reference are customers of the Companies.**

d. **I do not have this information.**

e. **My understanding is that the referenced large users are evaluating the costs, benefits, and viability of such projects.**

f. **I do not have this specific information; however, WVEUG members include companies with individual loads approaching 50 mW.**

g. **That is my understanding.**

Prepared by: Stephen J. Baron
Principal and President, J. Kennedy and Associates, Inc.

Date: September 15, 2017

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West Virginia Energy Users Group's ("WVEUG")
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Question 8:

Reference Baron direct, page 9, line 8 to page 10, line 7.

a. When you use the term "onsite cogeneration," does "onsite" mean the generation is behind the meter?

b. When you use the term "onsite cogeneration," does "onsite" mean the generation reduces the customer's load and usage?

c. Is decentralized generation "onsite?"

d. Does decentralized generation lower the customer's load and usage?

e. Is microturbine generation "onsite?"

f. Does microturbine generation lower the customers' load and usage?

g. State what you project to be the load loss from large users' onsite generation for the Companies' territories from 2017 through 2031 and produce all calculations and work papers supporting this projection.

h. State what you project to be the load loss from large users' decentralized generation for the Companies' territories from 2017 through 2031 and produce all calculations and work papers supporting this projection.

i. State what you project to be the load loss from large users' microturbine generators for the Companies' territories from 2017 through 2031 and produce all calculations and work papers supporting this projection.

Response:

a. On-site cogeneration could be generation behind the meter, in which case the energy would be used exclusively to supply the customer's energy needs.

b. Please see the response to part (a). Alternatively, the customer could have excess energy that could be sold to the Companies pursuant to PURPA regulations.

c. It is my general understanding that "decentralized" means on-site to the customer's energy consuming facilities.

d. Please see the response to part (b).

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e. **Yes.**

f. **Yes, assuming that the load was previously taking service from a utility before microturbine installation.**

g. **I have not performed the requested analysis.**

h. **Please see response to part (g).**

i. **Please see response to part (g).**

Prepared by: Stephen J. Baron
Principal and President, J. Kennedy and Associates, Inc.

Date: September 15, 2017

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

Case No. 17-0296-E-PC

MONONGAHELA POWER COMPANY and
THE POTOMAC EDISON COMPANY

Petition for Approval of a Generation Resource
Transaction and Related Relief

REBUTTAL TESTIMONY OF

DALE EVANS

September 18, 2017

Q. Please state your name and business address.

A. My name is Dale Evans and my business address is #1, Power Station Blvd, Willow Island, WV 26134.

Q. Who are you employed by and in what capacity?

A. I am employed by FirstEnergy Service Company at Pleasants Power Station as Technical Services Manager. I assist on numerous maintenance and capital projects throughout the Pleasants station and also work on improving the day-today operations of the plant.

Q. Please describe your professional experience and background.

A. I have worked within the power generation industry since graduation from West Virginia University in 1990 with a Bachelor of Science degree in Mechanical Engineering. After graduation, I began my career with Dominion Energy working at Beechurst Power Station in Morgantown, WV. In 1992, I came to work for Allegheny Energy (and FirstEnergy following the merger in 2011) and worked for seven years at Mitchell Power Station in Monongahela, PA. I subsequently spent seven years working at Hatfield Power station in Masontown, PA, several months intermittently working at Lake Lynn Hydro station in Lake Lynn, PA, followed by seven years at Ft. Martin Power Station in Maidsville, WV. For the last six years I have been working at Pleasants Power Station in Willow Island, WV.

Q. Did you file direct testimony in this case?

A. No, I did not.

Q. What is the purpose of your rebuttal testimony?

A. I will address assertions made by opposing witnesses that characterize Pleasants as a deteriorating asset facing significant performance issues and other issues raised about Pleasants' condition and performance. My testimony will address issues regarding investment and plant reliability, maintenance and O&M costs, operating parameters, turbine efficiency and heat rate, boiler, and waste disposal and environmental costs.

I. Investment; Plant Reliability

Q. Mr. Kumar asserts on page 4 of his direct testimony that FirstEnergy has inadequately invested in Pleasants to maintain ongoing reliability. Do you agree with this assessment?

A. No. Pleasants maintains a practice of continually evaluating plant components and then performing life-extensions or capital replacements when and where necessary. The plant units have had scheduled outages every three years, and the plant has been extremely well maintained. AE Supply, and Mon Power prior to divesting in late 2013, have adequately invested in the plant.

Q. How do plant personnel determine if capital needs to be invested to keep the plant running reliably?

A. Pleasants employs a regimented inspection program and conducts scheduled outages to ensure the reliability of the operating units. Through the Major Component Integrity Assurance ("MCIA") program, Component Health Reports, Advanced Pattern Recognition ("APR"), Original Equipment Manufacturer ("OEM") advisories, and industry peer correspondence, Pleasants balances both Capital expenditures ("CAPEX")

and Operation and Maintenance ("OPEX") expenditures to achieve consistent operating performance within corporate, industry, and regulatory objectives. With the exception of safety and environmental projects, all capital projects are evaluated based on an economic justification model to ensure cost-effectiveness.

Q. Please elaborate on the use of APR testing.

A. The site uses APR testing technology to monitor performance of the equipment and systems within the plant. Inputs from these systems are utilized to effectively plan and schedule equipment maintenance intervals. This methodology is an industry-recognized best practice and is proven to be an effective identification tool (rather than the more common time-based maintenance interval approach).

Q. Can you point to any specific examples of actions taken or equipment replacements that have taken place at Pleasants to ensure continued reliability?

A. Yes. Some examples include (but are not limited to):

- Boiler Components
    - Installation of laser cladded panels in the furnace
    - Selected waterwall panel replacement and overlay based on inspection results
    - Pendant finishing superheater replacement
    - Pendant reheat replacement
- Feedwater Heaters
- Main turbine rotor trains
- Generator rotor component upgrades

- Generator stator rewind
- Upgraded the distributed control systems
- Major plant infrastructure (i.e. new stack)
- Gypsum plant installation
- Addition of Selective Catalytic Reduction (SCR) system
- Conversion to Full-Scrubbing

As I noted above, Pleasants continuously evaluates all system components and performs replacements as appropriate.

Q. On page 38 of Mr. Kumar's testimony, he seems to assume that a plant's age necessarily requires additional planned outages and CAPEX and OPEX expenditures to prevent high impact low probability (HILP) events? Do you agree?

A. No. In fact, Mr. Kumar even states on page 38 that "HILP events can be avoided with inspection and maintenance spending." Pleasants has long incorporated a major component integrity assurance program and a high energy piping program that defines inspections to be completed during scheduled outages to prevent the potential of a HILP event. In addition, Pleasants also has a robust operational program in place that incorporates Plant Information data, ETAPro Data, site daily performance meetings, APR, standards for operation procedures and alarm responses. These data sources and operational standards are used to monitor operating unit conditions at all times (24 hours a day) ensuring that the plant is operated within design limits and providing plant personnel an opportunity to address concerns ***before*** they become an issue. HILP events are typically associated with new materials like T91 and new components. Pleasants

does not have those new components made of those materials. The Pleasants station was designed utilizing industry proven materials and components that have served the utility industry for years, the reduced failure modes for these materials is a result of many years of industry experience and industry collaboration to develop our inspection protocols and refine operational limits. This knowledge base allows for the full understanding of the health of our components. Furthermore, Pleasants uses this data and industry collaboration to continuously refine and improve its operating practices and procedures to avoid any cycling or creep damage mechanisms. These inspection practices have been in place for many years and use of these practices mitigates increased costs.

II. <u>Maintenance; O&M Costs</u>

Q. How would you describe the maintenance practices employed at Pleasants?

A. The operating and maintenance practices at Pleasants are based upon industry best practices utilizing the Electric Power and Research Institute's Maintenance Basis Templates to define our preventive maintenance practices. The Maintenance Basis templates are specific for plant equipment and were developed through industry collaboration. Among the best practices used at Pleasants are a very robust operator training program with an on-site simulator, daily work management practices, and outage work management practices. Industry peers recognize Pleasants as a leader in plant processes. Power station personnel from an Arizona plant visited Pleasants in 2014 for multiple days to identify ways to improve their own plant's processes.

Q. Please describe the Pleasants maintenance program.

A. Pleasants Power Station maintains a strong operations/maintenance history:

a. Daily Work Management System. The work management system for the plant utilizes SAP as the work management software and Primavera for the work scheduling software. The work management system defines the process for work identification, notification entry, repair planning standards, and the execution of the work requested. All work orders are prioritized within SAP based on the performance impact for the station and scheduled for execution accordingly. The work management process also defines the forums to review new notifications entered as well as a full review of any backlog work by all plant departments to continue to monitor the health of the station.

b. Outage Work Management System that mirrors the Daily Work Management process

c. Robust Inspection and Monitoring programs that include:

   i. Major Component Integrity Assurance (MCIA) – The MCIA program defines required inspection requirements and intervals required on plant equipment that could experience HILP failure if they were not inspected.

   ii. Component Health Reports (CHR) – CHRs are developed on major plant equipment. These reports summarize failure history, inspection results, and recommended future actions to enable proper outage planning.

iii. APR – APR is a real time modeling system that analyzes plant operating inputs and anticipates necessary inspection or maintenance activities to prevent failure.

iv. Correspondence with OEM and Electric Power and Research Institute (EPRI).

These inspection and monitoring programs look at systems and equipment very carefully and with extreme diligence to identify, prioritize, and plan for any item identified during the inspection.

Q. Because of the strong operating and maintenance practices at Pleasants, are future O&M expenses likely to remain stable?

A. Yes. As someone who knows the plant well, I can attest to the rigorous inspection and maintenance practices that allow us to keep the plant operating reliably and cost-effectively. As a result of these maintenance practices I described above and history of the plant, there is no reason to project that the plant will experience any significant upward trend in O&M costs.

Q. Mr. Kumar describes concerns resulting from creep on page 15 of his direct testimony. Do you believe creep is a concern at Pleasants?

A. No. Creep is a long term overheating failure mode in materials that occurs from operating the unit outside of operational limits. The Distributed Control System (DCS) as well as our operations and maintenance training programs (that have been in place for many years in this industry) followed at Pleasants help to ensure proper practices to minimize this failure mechanism. The condition is monitored as part of our regular

outage inspection program for areas where localized creep could occur. For example, independent Non-Destructive Examination (replica testing) is completed on major boiler headers during every scheduled outage to help indicate component condition. Based on these past analyses, there are no emerging creep concerns at Pleasants Power Station.

III. Operating Parameters

Q. Mr. Kumar theorizes that increased cycling operation will lead to increased spending and maintenance and a reduction in reliability, performance, and efficiency. (Page 4, 5) Please describe the operating parameters at Pleasants and how this concern is unfounded.

A. Mr. Kumar seems to assume that Pleasants will be operated as a cyclical unit. A cyclical unit is one that is removed from service on a regular basis to react to low system needs, the cyclical operation leads to reliability concerns due to the number of thermal cycles the unit sees going from full temperature and pressure operation to ambient temperature and pressure conditions. Due to the thermal cycles for cyclical units the result is an increase in the presence of cyclical fatigue. Pleasants has not been operated or dispatched in a cyclical operational mode.

Pleasants operates as a base load unit. Load following is defined as a unit that l regulates its generation output to match system demand above the minimum output established. Each unit at Pleasants will operate in a band between 300 MWs and 650 MWs dependent on system needs. Operating in between this output band is done such that the unit is maintained within design conditions for feedwater flow, steam temperature, and steam pressure. This minimizes the impact of cyclical fatigue.

Q. Is cycling fatigue still a factor in all power plants?

A. Yes, while cycling fatigue is a factor in all power plants, regardless of age, a cyclical plant has much more cycling fatigue than a base load station like Pleasants. Pleasants employs regimented inspection programs and scheduled outages to ensure the reliability of the operating units, and it implements Major Component Integrity Assurance, Component Health Reports, APR, OEM Technical Advisories, industry best practices, and regular correspondence with EPRI. Based on these monitoring and inspection practices, we plan the necessary repairs and replacements. This operating philosophy maximizes the useful life of all systems within the plant, regardless of age. To help ensure as-designed and conservative operation, Pleasants has a very robust training program for operations and maintenance employees. These practices allow the plant to minimize effects of cycling fatigue.

IV. Turbine Efficiency and Heat Rate

Q. Mr. Walker expresses concerns regarding the operation, performance and maintenance of Pleasants Power Station. What practices does Pleasants employ to monitor heat rate?

A. Pleasants Power Station uses ETA Pro heat rate monitoring software and Delta V testing (turbine efficiency) to monitor the heat rate of the generating units; the heat rate for each unit is reviewed daily. Heat rate issues identified through this review are entered into our Work Management System and actions needed to correct the condition are executed. The station also prioritizes heat rate improvements and corrective actions by monitoring the station's controllable heat rate losses daily; the top five losses are listed by unit, in a

priority order. An example of this would be monitoring condenser performance for required water box cleaning. In short, I believe that the heat rate and turbine efficiency are handled in accordance with best engineering practices, and that Staff's position is unfounded.

V. <u>Boilers</u>

Q. Mr. Kumar and Mr. Walker seem concerned about the boiler, specifically tube failures. What practices does Pleasants employ to deal this?

A. Pleasants utilizes boiler tube cladding, improved boiler tube base metals, laser cladding, and weld metal-overlay protection. Although Mr. Kumar does not acknowledge it, the EPRI study referenced on page 31 of his testimony showing a correlation between unit age and increases in outage rate is very outdated—it was conducted from 1974 to 1983. Importantly, the study, which is specific to boiler tube failures, predates the practices I described above used to combat boiler tube failures. My previous experience with EPRI and various welding vendors was first-hand and allows me to comment on the evolution of boiler tube "armoring." The weld metal-overlay process was refined in the mid-1990s, and the improved understanding of weld metal "armoring" made its use a viable option in the utility boiler industry. Laser clad boiler tube panels also became an option for improved "armoring" afterwards, in the mid to late 1990s. Since that time, many electric utilities utilize "armoring" techniques to improve boiler reliability.

The boilers at Pleasants are in very good shape and can last for many decades. The following significant work has been performed: Pendant finishing Super Heat sections have been replaced, as-necessary. #1 and #2 Pendant Reheat sections have been

replaced. The condition of the Reheat Outlet Headers is good; this condition is verified with NDE methodology during planned outages. Primary furnace boiler tubes are Non-Destructive Examination (NDE) tested during planned outages; necessary areas are replaced with panels, weld-overlayed, or metallized to help ensure reliable operation between planned outage cycles (every 3 years).

VI. Waste Disposal and Environmental Compliance Costs

Q. Mr. Dove asserts that little capacity remains at the McElroy's Run Impoundment and that the plant will need an alternative means to dispose of waste currently disposed at McElroy's Run. How will this issue be addressed?

A. Waste coal combustion by-products, including scrubber sludge, are disposed on-site in either the dry landfill or the wet impoundment, or sold for beneficial reuse. The materials going to the dry landfill include fly ash, bottom ash, gypsum, dry vacuum truck (mostly fly ash), and waste water treatment plant solids. The materials going to the wet impoundment (often referred to as "McElroy's Run") are by-products from just the scrubber waste that cannot be converted into gypsum. Scrubber slurry goes through a separation process to actually produce gypsum at the plant and a liquid waste material to be disposed of at McElroy's Run. The gypsum produced at the station is sold to a manufacturer of dry wall boards for commercial and residential use or disposed of at the dry landfill.

The dry landfill currently has 2,500,000 cubic yards of available space. The fill rate based on historic data (not including gypsum) is 327,000 cubic yards per year. The

engineering has been completed for the next expansion of the dry landfill and will provide an additional 5,000,000 cubic yards of capacity.

The wet impoundment has the remaining capacity of 1,546,600 cubic yards, based on a June 2017 fathometer study. The fill rate based on the change in remaining volume from the June 2015 to June 2017 fathometer studies is 144,936 cubic yards per year.

The August 2017 calculated remaining life of the wet impoundment is 10.67 years. Based on this life, Pleasants will install Best Available Technology equipment to produce dry material for McElroy's Run disposal site for the dry landfill prior to the end of life of the impoundment.

Allegheny Energy Supply recently signed a long-term agreement to provide all spec gypsum material to a leading wallboard manufacturer, which will be assigned to Mon Power as a condition of the sale. With this agreement in-place, the only dry disposal material would include bottom ash (some bottom ash is sold to various highway departments) and fly ash. The agreement to sell all gypsum produced significantly reduces the amount of dry material that would be placed into the dry landfill.

Q. Does McElroy's Run need to be included in the transaction?

A. Yes, the impoundment is needed to operate the plant. It is a part of the bid made by AE Supply and is a part of the transaction.

Q. Are you aware of the stay of the EPA's effluent limitations guidelines rule (ELG Rule)?

A. Yes. In April of this year, after the bids were made, the EPA announced that it will re-review and reconsider the ELG Rule in light of the stay. As drafted, the ELG rule would

have affected our scrubber sludge and bottom ash operations as those materials are transported through a wet sluicing conveyance system. It would not affect our fly ash transport since that material remains dry and is hauled in a dry form to the landfill.

Q. How will the court's stay affect the plant's environment compliance portion of the capital expenditure budget?

A. While the stay is likely to result in a delay in implementation, modification or elimination of the rule, the Company will continue working with EPRI and the company CH2M (or other 3rd party vendor) to identify Best Available Technology options that could be installed at the Pleasants Power Station should some form of the rule remain intact. This technology and associated equipment would produce a solid material from the scrubber sludge and bottom ash wet transport sluice materials that will be hauled to the dry landfill area at Pleasants Power Station after the impoundment is filled, which as noted above currently is expected to be in 10.67 years. The concern with the ELG, its technology, and the costs no longer has an imminent impact on the plant.

Q. Mr. Dove mentions in his testimony the remaining impoundment life estimate and makes a statement regarding Coal Combustion Residuals (fly ash and bottom ash) going to the impoundment (page 14, line 25). Do you agree with this statement?

A. No. Mr. Dove mistakenly believes that ash is being disposed of in the impoundment today. Neither bottom ash nor fly ash is being disposed of in the McElroy Run's impoundment. All ash material is trucked to the dry landfill. Only liquid effluent that cannot produce gypsum from the scrubbers is pumped to the wet impoundment, and that is the only material going to the impoundment.

Q. Please summarize your testimony

A. Pleasants is an excellent operating plant, it has had robust capital and maintenance expenditures and care, and the concerns raised by the intervenors are not grounded in fact.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

Case No. 17-0296-E-PC

MONONGAHELA POWER COMPANY and
THE POTOMAC EDISON COMPANY

Petition for Approval of a Generation Resource
Transaction and Related Relief

REBUTTAL TESTIMONY OF
RAYMOND E. VALDES

September 18, 2017

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Raymond E. Valdes, and my business address is 800 Cabin Hill Drive, Greensburg, Pennsylvania 15601. I filed direct testimony on behalf of Monongahela Power Company ("Mon Power") and The Potomac Edison Company ("PE," and together with Mon Power, the "Companies") on March 7, 2017, as revised on April 3, 2017 to reflect an amendment to the Companies' pro-forma journal accounting entries.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I will address rate-related recommendations of Staff witnesses Edwin L. Oxley, Randall R. Short and Terry R. Eads, West Virginia Energy Users Group ("WVEUG") witnesses Stephen J. Baron and Lane Kollen, and West Virginia Citizen Action Group/West Virginia Solar United Neighborhoods/Community Power Network ("WVCAG-SUN") witness David A. Schlissel.

Temporary Surcharge Issues

Q. WHAT ARE STAFF'S RECOMMENDATIONS ON THE COMPANIES' PROPOSED TEMPORARY SURCHARGE?

A. Staff witness Oxley recommends that if the Public Service Commission of West Virginia ("Commission") approves the purchase of the Pleasants Power Station ("Pleasants"), it should also approve the Temporary Surcharge for recovery of the plant's additional cost of service. However, Staff does not believe the Companies should be permitted to recognize a regulatory asset or liability calculated by comparing Temporary Surcharge

actual revenues against actual costs. Oxley at 5-6. Further, in lieu of a return on equity ("ROE") of 10% as the Companies propose, Staff witness Oxley believes the Commission should utilize a ROE of 9.75% in the Temporary Surcharge calculation. Oxley at 11.

Q. DO YOU AGREE WITH STAFF'S RECOMMENDATIONS?

A. I agree the Temporary Surcharge should be approved by the Commission. However, the Temporary Surcharge should be reconcilable as proposed by the Companies and an ROE of 10% should be utilized in the Temporary Surcharge calculation.

Q. WHY DOES STAFF RECOMMEND ELIMINATING THE RECONCILABLE COMPONENT OF THE TEMPORARY SURCHARGE?

A. Staff witness Oxley asserts that, for the most part, surcharges involving the purchase or construction of electric generating assets do not include a reconciliation provision. He acknowledges, however, the transfer of the Harrison Power Station ("Harrison") in Case No. 12-1571-E-PC, where the Commission authorized a reconcilable transaction surcharge through its approval of a Joint Stipulation and Agreement for Settlement.[1]

Q. WHY DO YOU DISAGREE WITH STAFF'S RECOMMENDATION?

A. The simple fact is that surcharges, which include collection of specifically tracked costs that are separate from costs embedded in base rates, are traditionally reconcilable. Reconciliation is a typical regulatory construct for surcharges, and there is nothing unique in the Temporary Surcharge that justifies a divergence. The Temporary

[1] The Joint Stipulation and Agreement for Settlement in Case No. 12-1571-E-PC was approved by Commission order dated October 7, 2013.

Surcharge collects incremental expenses related to the Pleasants transaction, including non-fuel operation and maintenance ("O&M"), depreciation, income taxes, taxes other than income taxes, and a return on the incremental rate base due to the increase in plant-in-service. These costs are not necessarily fixed, but instead change over time. Similarly, revenues change over time and are forecasted by the Companies to increase. However, no one can be certain that revenues will be in alignment with costs. A reconcilable surcharge provides the precision of placing costs and revenues in alignment, benefiting both customers and the Companies. In other words, a reconcilable Temporary Surcharge helps ensure that the Companies can recover their costs, while at the same time benefiting customers with the assurance of refunding over-collected amounts, if any. The benefits and precision associated with a reconcilable surcharge should not be abandoned simply based upon the premise that base rates are traditionally not reconcilable.

Q. IS THE TEMPORARY SURCHARGE UNIQUE IN THE COLLECTION OF CAPITAL AND O&M COSTS ON A RECONCILABLE BASIS?

A. No. The Companies' Vegetation Management Surcharge is also reconcilable. The Vegetation Management Surcharge collects all O&M costs and capital costs placed in service as of the effective date of the surcharge. When such vegetation management costs were reflected in base rates, there was no reconcilable component to these costs. However, as of the effective date of the Vegetation Management surcharge, such vegetation management costs were, and still are, reconcilable. The same ratemaking paradigm should apply to the Temporary Surcharge.

Q. HOW COULD OVER-RECOVERIES OF THE TEMPORARY SURCHARGE OCCUR?

A. As provided in the Companies' petition and correctly noted in the direct testimony of Staff witness Oxley, the Companies have experienced sales growth in its West Virginia operating territory and more growth is anticipated. Even if costs attributable to the Temporary Surcharge were to increase beyond the 2016 test year amounts, the growth in sales (and subsequently revenue) could outpace any change in costs, thereby contributing to an over-recovery. This over-recovery can be exaggerated if costs were to decrease from the amounts included in the 2016 test year. While the opposite could occur, this again illustrates the point that the Companies' reconciliation proposal is a protection for the Companies and customers alike by ensuring the Companies would be made whole for any net under-recovery and customers likewise would recoup any net over-recovery. Additionally, as a separately identifiable surcharge, revenues can be separately identified and tracked, compared to costs, and presented to the Commission through a reconcilable process on an annual basis. This is not reasonably possible for base rate components under traditional ratemaking. For these reasons, the Temporary Surcharge should be reconcilable during the period it is in effect, which is from the date of closing of the Pleasants transaction until new base rates reflecting the full amount of the Temporary Surcharge revenue requirement are placed into effect.

Q. WHY DOES STAFF RECOMMEND USING AN ROE OF 9.75% IN THE TEMPORARY SURCHARGE CALCULATION?

A. Staff witness Oxley believes an ROE of 9.75% should be used to be consistent with the ROEs last determined for West Virginia-American Water Company and Appalachian Power Company.

Q. WHY DO YOU DISAGREE?

A. Staff's recommendation is not based on recent studies or analyses of the Companies' cost of capital. Rather, the recommendation is based upon the ROEs for separate, unaffiliated companies, without any determination of whether those utilities are representative of the Companies or whether those ROEs are representative of the Companies' cost of capital.

The last time the Commission established an ROE for the Companies in a fully-litigated, non-settlement proceeding was in May 2007 in Case No. 06-0960-E-42T, where the Commission authorized an ROE of 10.5%. Since then, the Companies have filed two base rate cases, both of which resulted in a settlement agreement that did not specify or determine an ROE for base rates. However, in the settlement agreement in the most recent base rate proceeding in Case No. 14-0702-E-42T, the Companies, Staff, and the Consumer Advocate Division ("CAD") each justified the base rate increase with an exhibit presenting an illustrative revenue requirement in support of the settlement. Although the Companies did not present an ROE in its exhibit, both Staff and the CAD presented an ROE of 9.9% for the Companies. Therefore, in the absence of a base rate case to debate and establish a new allowed ROE, a reasonable range of ROEs specific to

the Companies would be between 9.9% presented by Staff and the CAD, and 10.5% last ordered by the Commission.

The 10% ROE proposed by the Companies has been used in several other settlement agreements specific to the Companies and described in my direct testimony. Although settlement agreements hold no precedential value in other proceedings, the use of an ROE is necessary in any calculation involving capital recovery. But whether or not a 10% ROE was utilized in prior settlement agreements, it falls between the ROE range of 9.9% to 10.5%. Simply put, the 10% ROE, which is below the mid-point of the 9.9% to 10.5% range, allows the Companies an opportunity to earn a level of revenue commensurate with its investment while balancing the interests of the public in receiving fair and reasonable rates. Instead of basing the ROE on another utility's cost of capital, the Companies proposed ROE of 10% should be used in the Temporary Surcharge calculation for the limited duration of the Temporary Surcharge.

Q. DOES WVEUG HAVE ANY RECOMMENDATIONS ON THE COMPANIES' PROPOSED TEMPORARY SURCHARGE?

A. Yes. WVEUG witness Baron recommends that if the Commission approves the Pleasants transaction, the Companies should defer the revenue requirements of the Temporary Surcharge, along with a return on the deferred balance, until those costs can be considered in a base rate case. Baron at 32-33. WVEUG witness Kollen recommends that changes in the pension and other post-employment benefits ("OPEB") expense

portion of the Temporary Surcharge due to under-funding or over-funding be excluded from ratemaking expense. Kollen at 13.

Q. DO YOU AGREE WITH THE RECOMMENDATIONS OF WVEUG?

A. No. The recommendation to defer the revenue requirements of the Temporary Surcharge is impractical and contrary to sound ratemaking. As provided in Exhibit REV-1 to my direct testimony, the Temporary Surcharge annual revenue requirement based upon a 2016 test year is $111.4 million. A deferral of this amount for just two years is $222.8 million. Aside from the additional carrying charge expense that would need to be applied to the deferral balance, WVEUG's recommendation would result in unnecessarily wild swings to customer rates. For example, as outlined in my direct testimony, the combination of the Temporary Surcharge increase and the Expanded Net Energy Cost ("ENEC") decrease results in a net decrease to customers, which is an approximate $24 million decrease in 2018. Without the Temporary Surcharge, customer rates would decrease due to the ENEC reduction by approximately $135 million in 2018, while at the same time accruing a deferral of approximately $111.4 million ***per year***. This asymmetric flow-through of ENEC proceeds but deferral of costs that effectuated the ENEC proceeds is not only a mismatch of revenues and costs, but also: (i) unnecessarily results in rate reductions only to be followed by rate increases, which is contrary to the fundamental ratemaking principle of rate gradualism; (ii) results in additional customer costs due to the carrying costs involved for a deferral in the hundreds of millions; and (iii) raises fundamental legacy issues and cost causation issues, where customers served by

the Companies during the period of the deferral experience all the benefits of a decreased ENEC while a potentially separate segment of customers bear all the costs in the future. Therefore, the deferral recommendation should be rejected by the Commission.

Regarding the recommendation of WVEUG witness Kollen to exclude increases in expense due to pension under-funding and decreases in expense due to OPEB over-funding, such a position is contrary to traditional ratemaking and is unnecessary. The inclusion of pension/OPEB expense due to under-funding or over-funding positions is a component of base rates and likewise should be reflected in the calculation of the Temporary Surcharge for Pleasants. There is no basis to expressly exclude this expense from rates, regardless of whether it is in base rates or a surcharge. As such, this recommendation by witness Kollen should be rejected by the Commission.

Q. ARE THERE ANY FINAL ITEMS TO ADDRESS REGARDING THE TEMPORARY SURCHARGE?

A. Yes. In his analysis of the Pleasants transaction, Staff witness Eads changed the depreciation expense based upon a 22-year remaining regulatory life for Pleasants as opposed to the 27-year remaining regulatory life for Pleasants as proposed by the Companies. Eads at 10.

The 27-year remaining regulatory life for Pleasants utilized by the Companies is based upon the depreciation study performed in Case No. 06-1426-E-D, where Pleasants was determined to have a 65-year service life, with an estimated retirement date of 2045. This service life was supported by CAD witness Majoros who stated, "a 65 year life span

is reasonable for steam production plant."[2] Further, in the Harrison transaction in Case No. 12-1571-E-PC, Company witness Wise also assumed a 65-year service life for Pleasants.[3] Use of the same 65-year service life results in the 27-year remaining regulatory life of Pleasants included in Exhibit REV-5-R to my direct testimony, which translates to an annual depreciation expense of about $7.2 million.

It appears Staff witness Eads changed the remaining regulatory life of Pleasants from 27-years to 22-years for modeling purposes and is not necessarily recommending a change to the Companies' depreciation expense. If, however, the Commission determines that a 22-year remaining regulatory life should be used in lieu of the Companies' recommended 27-year remaining regulatory life, the Temporary Surcharge would increase by approximately $1.7 million per year to reflect an increase in depreciation expense from $7.2 million to $8.9 million per year.

Sharing Mechanisms

Q. DO YOU AGREE WITH THE RECOMMENDATIONS RELATED TO SHARING MECHANISMS PUT FORTH BY STAFF, WVEUG, AND WVCAG-SUN?

A. No. Traditional ratemaking is not based upon such a risk sharing mechanism and it would be contrary to well established ratemaking principles to include one in this transaction. Instead, ratemaking is cost-based, whereby the total annual revenue

2 Direct Testimony of Michael J. Majoros, page 18.

3 Direct Testimony of Kevin G. Wise, Exhibit No. KGW-7 listed the remaining regulatory life of Pleasants at 32 years, which translates to a 65-year service life.

requirement includes an amount that will yield an opportunity to earn an annual return on the value of property used and useful in public service, plus operating expenses, taxes, and depreciation. The ratemaking process determines a utility's revenue requirements and sets the rates for service accordingly. This is the regulatory construct that has been followed in West Virginia for many years and that remains in place today. At no point does the risk sharing proposed by the intervenors ever enter the cost-based ratemaking process; nor should it as the risk sharing recommendation is not cost-based. The cost basis for Pleasants resulted from an independently managed request for proposals. Pleasants was by far the lowest price generation asset offered in the competitive solicitation and the resultant price should be the cost basis for ratemaking purposes.

Moreover, Mon Power's Fort Martin and Harrison Power Stations, and other former power plants such as Willow Island, Rivesville, and Albright, have all been rate-based during rate base filings with recovery of costs and an opportunity to earn a fair return on the asset. These intervening parties are now recommending a rate treatment wholly different from traditional rate treatment and inconsistent with the regulatory framework in West Virginia, and I am advised by counsel that such an unorthodox rate treatment would present serious legal concerns. Either the asset is excluded from rates (or in this case acquisition) or it is included with Commission-authorized rate recovery. The parties do not cite applicable statutory authority for their unorthodox rate sharing proposal because the Companies do not believe there is any such authority.

The Companies are aware of instances where they have shared in a portion of the benefits of off-system sales back in the 1980s and early 1990s through the ENEC and were permitted to keep a portion of those off-system revenue sales. However, the Commission eliminated that practice decades ago in asserting that 100% of those benefits must flow back to customers and that the Companies could not share in any of those gains. The Commission and parties need to be consistent in their application. It should not require all the revenues be returned to customers when sales and markets are high and then do the opposite and require Company risk sharing, as proposed by the intervenors, when they believe markets are low or pose risk. Secondly, those off system sales did not impose financial harm or risk upon the Companies as they could only gain from such sales and could never lose. So there was really no risk sharing with those off-system sales --- just a sharing of the benefits, which, again, was eliminated by the Commission.

Notwithstanding the attempt to impute an improper risk sharing provision into the ratemaking process, there are multiple issues with the recommendations put forth by Staff, WVEUG, and WVCAG-SUN.

Q. PLEASE DESCRIBE THE CONCERNS YOU HAVE WITH THE RISK SHARING RECOMMENDATIONS OF STAFF, WVEUG, AND WVCAG-SUN.

A. Staff witness Short proposes to use Mon Power's costs and revenues from the PJM market as an asymmetric means to apportion risk in the Pleasants transaction. He recommends that if Pleasants' net operating costs exceed PJM market revenues from Pleasants, then customers would pay only the equivalent of the PJM market, with the

Companies bearing the difference. Simply put, he proposes that customers pay the lower of cost or market which is not the regulatory construct in West Virginia. His proposal becomes more egregious when he proposes a 75%/25% sharing mechanism if revenues exceed costs, where 75% of the economic benefits go to customers and 25% of the economic benefits go to the Companies, with the 25% being decreased by 5% every two years until it reaches 0% after ten years. His proposal has customers completely insulated from any downside risk from the Pleasants acquisition but allows them to enjoy the vast majority of the upside benefit. Short at 15-17. WVEUG witness Baron and WVCAG-SUN witness Schlissel have both proposed similar mechanisms, although witness Schlissel's recommendation is not well-defined and, similar to the Short and Baron recommendations, appears to be asymmetrically biased against the Companies. Baron at 29-30 and Schlissel at 70.

Q. DO YOU HAVE OTHER CONCERNS ABOUT THE RISK SHARING MECHANISMS PROPOSED?

A. Yes. First, using the PJM market as a benchmark for the Companies' entitlement to cost recovery is inappropriate because the PJM market is not risk-free and continuing to expose customers to the risks of the PJM market while knowingly prolonging a capacity-deficient position is contrary to the Commission's prior direction to the Companies that "[f]ailure to deal with the market risk inherent in MP/PE capacity deficit is unacceptable."[4] Evaluating the risk level presented by the Pleasants transaction with reference to the PJM market is effectively comparing one set of risks to a different set of

4 Order dated October 7, 2013, page 24, in Case Nos. 12-1571-E-PC and 13-1272-E-PW.

risks, which is improper. Stated differently, this method of evaluation effectively assumes that: (i) reliance on the PJM market is essentially risk-free; and (ii) the only risk facing customers is the incremental risk associated with the Pleasants transaction. Neither of these assumptions is justified. The fact is that acquiring Pleasants as additional capacity, in addition to meeting a capacity deficiency, is also an effort to abate the market risk associated with reliance on the market. This is exactly what the Commission previously directed in the Harrison transaction.

Secondly, since the Pleasants transaction offers the benefits of addressing a capacity deficiency and reducing PJM market risk, it should be evaluated not against the PJM market risk it is designed to abate, but against the other resources available to provide those benefits. The Companies issued a request for proposals ("RFP") to provide this comparison. In that process, the Companies sought to acquire demand resources to satisfy future capacity needs, engaging Charles River Associates ("CRA"), an independent and nationally recognized consultant, to assist in the preparation, administration and evaluation of the RFP. Based on CRA's analysis of the bids received in the RFP, the winner was Pleasants, which means it was the resource identified that could provide these benefits at the most favorable estimated rate impact for customers. Consequently, rather than inventing a risk-sharing mechanism that measures Pleasants' benefits against the PJM market, the appropriate comparison should be against the other reasonably comparable generation options that emerged from the RFP.

Q. WASN'T THERE AN ADJUSTMENT TO NET MARGINS FOR OFF-SYSTEM TRANSACTIONS IN THE HARRISON CASE?

A. Yes, it did, but there the circumstances were entirely different. Condition #3 in the Harrison Order established an adjustment for net margins for off-system transactions, but it related only to a portion of the ***acquisition adjustment*** the Commission permitted the Companies to recognize in rates. Furthermore, this condition was in the same vein as a stipulated settlement condition, because the Companies had the option to accept or reject it. In this acquisition, however, the Companies have not proposed an acquisition adjustment of any kind; Pleasants' purchase price is the same as its book value, which has already been written down substantially from the book value it had when Mon Power transferred its interest in Pleasants to AE Supply in 2013. The Commission did not impose a "risk-sharing" mechanism associated with cost recovery for the book value of Harrison, yet that is what WVEUG, Staff, and WVCAG-SUN propose here.

Q. WVEUG WITNESS BARON POINTS TO A RATEMAKING MECHANISM USED IN A WHEELING POWER COMPANY CASE TO SUPPORT HIS PROPOSAL. SHOULD THE COMMISSION USE THIS AS PRECEDENT FOR MR. BARON'S RISK-SHARING PROPOSAL?

A. No. The ratemaking mechanism used in Wheeling Power Company's Mitchell plant acquisition case[5] is from a Joint Stipulation and Agreement for Settlement. As expressly agreed to, the settlement reflected substantial compromises by the stipulating parties, and the provisions of the settlement agreement are made without adopting any of the

5 Case No. 14-0546-E-PC.

compromise positions as ratemaking principles applicable to future proceedings. As such, that case offers no precedential value for the sharing mechanism WVEUG proposes in this case.

Q. WHAT OTHER FLAWS ARE ASSOCIATED WITH THE SHARING MECHANISM PROPOSALS?

A. The Staff, WVEUG, and WVSUN-CAG risk-sharing proposals are uniquely biased against the Companies since the sharing mechanisms are asymmetric; meaning costs can only go down if the PJM market is lower than forecasted, but costs cannot necessarily increase if the PJM market is higher than forecasted. Aside from the prior discussion that a sharing mechanism is unnecessary in the Pleasants transaction, if the Companies are exposed to cost disallowance if the PJM market is lower than forecasted, then the Companies need to be entitled to an equal and opposite benefit if the PJM market is higher than forecasted. This asymmetrically-biased position is yet another reason why the sharing mechanism proposal should be rejected by the Commission.

Economic Stability Credit

Q. WHAT IS YOUR RESPONSE TO MR. BARON'S RECOMMENDATION THAT AN "ECONOMIC STABILITY CREDIT" BE RE-IMPOSED AS A CONDITION OF TRANSACTION APPROVAL?

A. Mr. Baron argues that in the event the Commission approves the Pleasants transaction and a Temporary Surcharge, the Commission should require the Companies to re-

implement an Economic Stability Credit ("ESC") of $0.00065 per kilowatt-hour ("kWh") for customers served on tariff Schedules K and PP.[6] He justifies this recommendation as a means to reduce the alleged risk and potential adverse impact of the transaction on West Virginia industry and manufacturing, and to address his claim that a subsidy is embedded in base rates. Baron at 34-35.

I disagree with this recommendation for several reasons. First, the ESC previously implemented by the Companies in the Harrison transaction was a provision in a Joint Stipulation and Agreement for Settlement.[7] As discussed previously, the mere fact that an ESC was included in a prior settlement agreement does not justify making it a condition on approval of the Pleasants transaction in this case.

Secondly, there is no evidence to suggest that any ESC, much less an ESC at $0.00065 per kWh, is fair, reasonable, or correctly calculated. The suggestion that the ESC can somehow be used to mitigate a subsidy issue in base rates is speculative and should be rejected by the Commission. The Companies' existing base rates are the result of a settlement agreement in Case Nos. 14-0702-E-42T and 14-0701-E-D, and that settlement agreement did not identify a cost of service subsidy issue between the various classes of customers. Absent a new cost of service study in the context of a base rate case, the existence, amount, and cause of a subsidy cannot be established just by looking at the existing level of base rates. Nor could we know now what positions on customer

6 Customers served on tariff Schedules K and PP are large-size commercial or industrial customers, with loads generally greater than 3,000 kVA and service voltages in excess of 10,000 volts.

7 Case Nos. 12-1571-E-PC and 13-1272-E-PW.

class allocation other parties to such a case would take, how those hypothetical subsidies should be addressed, or how the Commission would rule on these complex issues. Aside from the fact that a temporary ESC was a settlement component in the Harrison case, Mr. Baron has offered no justification for an ESC, and there is no evidentiary basis to find that imposing an ESC would be just and reasonable. In fact, the filed rates in the Pleasants transaction would provide WVEUG's clients a reduction in rates of 3-4% on average based on their load factor, with an allocation factor for the Temporary Surcharge that WVEUG witness Baron asserts is correct and appropriate.[8] Further rate benefits do not need to be bestowed upon those industrial customers.

Base Rate Case

Q. WHAT RECOMMENDATION HAS WVEUG MADE REGARDING A FUTURE BASE RATE CASE?

A. WVEUG witness Baron recommends that regardless of whether the Commission approves a Temporary Surcharge or deferral accounting for the Temporary Surcharge, he believes the Commission should require the Companies to file a base rate case in 2019 with rates effective January 1, 2020. Mr. Baron claims that the base rate case is needed to address the same alleged subsidies being paid by large West Virginia industrial customers. Baron at 34.

[8] Baron at 32.

Q. WHAT IS YOUR RESPONSE TO THE RECOMMENDATION TO FILE A BASE RATE CASE?

A. The recommendation is fundamentally unnecessary, unsupportable, and contrary to prior claims by WVEUG. As previously discussed, there is no evidence showing that subsidies are being paid by large West Virginia industrial customers, let alone the level of such subsidies (if they do exist), and which customer class is paying the subsidies. As such, there is no evidence of subsidies to support the need for a base rate filing.

Secondly, since WVEUG's recommendation is made regardless of whether the Commission approves a Temporary Surcharge and since the Temporary Surcharge is part and parcel to the Pleasants transaction, the recommendation is, in essence, unrelated to this proceeding and should not be a consideration by the Commission in determining whether the Pleasants transaction is approved.

Finally, the recommendation to require a base rate filing is curious in light of the claims by WVEUG that further rate increases will only exacerbate the deterioration of industrial and manufacturing competitiveness in the Companies' service areas. Data provided during discovery show that the Companies are under-earning in 2016. If such a scenario were to continue into a test year, then the Companies would likely be filing for a base rate increase. Absent any known level of subsidies, it is impossible to determine whether a subsidy reduction or elimination would offset a base rate increase. In short, the industrial and manufacturing customers could be worse off, rather than better off, if a

base rate case were required to be filed. For all the foregoing reasons, the Commission should reject this proposal.

Accumulated Deferred Income Taxes

Q. HAVE THERE BEEN ANY RECOMMENDATIONS REGARDING ACCUMULATED DEFERRED INCOME TAXES?

A. Yes. WVEUG witness Kollen recommends that the Commission reject the Companies' proposed accounting entry to create a new accumulated deferred income tax ("ADIT") entry in FERC account 190 equivalent to the amount in FERC account 282. If the Commission does not reject the Companies' proposed accounting entry, witness Kollen recommends the Commission exclude ADIT from rate base in the calculation of the Temporary Surcharge. Kollen at 9.

Q. DO YOU AGREE WITH THESE RECOMMENDATIONS?

A. No. ADIT results from timing differences between book and tax depreciation rates. Because there is no cash impact associated with the ADIT balance, it should not be deducted from the Temporary Surcharge rate base. The ADIT asset and liability associated with the Pleasants transaction equally offset one another, resulting in no change to rate base. For this reason, the Companies' pro-forma accounting entry is correct.

Q. PLEASE EXPLAIN.

A. It will help to understand the situation if I provide an example, as shown below:

	FERC Account	BEFORE SALE	
		Seller	Mon Power
Plant			
Gross Plant	101-107	$ 1,000	
Reserve	108	$ 200	
Net Plant		$ 800	
Cash	131		$ 800
Deferred Debits			
ADIT	190		
Deferred Credits			
ADIT	282	$ 200	
ADIT	283		
TAX RECORDS			
Tax Basis of Plant		$ 300	
Taxable Gain			

This example is before the sales transaction, and I have assumed the seller has a piece of plant at an original cost of $1,000 but has depreciated by $200 to result in a net plant value of $800. The $800 is also the sales price. The $200 accumulated depreciation in this example is straight-line depreciation, which is typical for regulatory depreciation. However, tax depreciation is typically faster than straight-line depreciation, and I have assumed that the accumulated tax depreciation is $700, which results in a plant tax basis of $300 shown above (i.e., $1,000 gross plant less $700 tax depreciation equals a $300 tax basis). The $300 amount and the $800 amount are both a view of net plant; the

difference is that the $300 is a tax basis and the $800 is a regulatory basis. To determine the ADIT, the difference between the $800 regulatory basis and the $300 tax basis is multiplied by the tax rate to determine the timing difference between book and tax depreciation rates. Using a 40% tax rate in this example yields a $200 ADIT as shown above (i.e., ($800 - $300) x 40% = $200). The $200 will eventually be paid to the taxing authorities, which is why it is an ADIT. Finally, I assume that Mon Power plans to pay cash for the transaction, which is also shown above.

Q. WHAT OCCURS AFTER THE SALES TRANSACTION?

A. After the sales transaction, Mon Power pays the seller $800 and records the plant values, assets, and liabilities on its books. Mon Power also needs to determine its tax basis on a going-forward basis. This is illustrated below, both before and after the sales transaction.

	FERC Account	BEFORE SALE: Seller	BEFORE SALE: Mon Power	AFTER SALE: Seller	AFTER SALE: Mon Power
Plant					
Gross Plant	101-107	$ 1,000			$ 1,000
Reserve	108	$ 200			$ 200
Net Plant		$ 800			$ 800
Cash	131		$ 800	$ 800	
Deferred Debits					
ADIT	190				$ 200
Deferred Credits					
ADIT	282	$ 200			$ 200
ADIT	283			$ 200	
TAX RECORDS					
Tax Basis of Plant		$ 300			$ 800
Taxable Gain				$ 500	

As shown above, plant values and cash values look similar before and after the sales transaction, except the $800 in cash paid by Mon Power is now reflected on the books of the seller in the cash account, and the gross, reserve, and net plant values of the seller are now reflected on the books of Mon Power. In accordance with FERC guidance in Docket No. AI98-2-000, the transfer of property is a taxable event that resulted in a deferred tax gain and established a new tax basis for the property transferred to the buyer, which in this example is Mon Power. The seller is required to recognize a deferred tax liability for the gain in account 283 and the seller is also required to reverse the deferred income taxes related to the property transferred from account 282. The seller had a tax basis of $300, so the taxable gain is $500 (i.e., $800 cash proceeds less the prior tax basis of $300).

Multiplying the $500 by the 40% tax rate equals the $200 that is eventually paid to the taxing authorities, which matches the $200 in ADIT retained by the seller to cover taxes that were deferred when it had ownership of the plant.

Mon Power does not receive the $200 ADIT as a cash payment because it will not be responsible for the payment of taxes due to the proceeds received by the seller. As such, Mon Power records the $200 ADIT in account 282 as a deferred credit, but records an equivalent $200 in account 190 as a deferred debit. Just as property-related ADIT credits in account 282 are traditionally a reduction to rate base, property-related ADIT debits in account 190 are traditionally an addition to rate base. Since the ADIT credits and debits associated with the Pleasants transaction equally offset one another, there is no change in rate base to reflect that no cash payment was received from the recording of the ADIT.

Q. WOULD THERE BE AN ADIT OFFSET TO RATE BASE IF THE SELLER WAS NOT A FIRSTENERGY AFFILIATED ENTITY?

A. No. There would be no ADIT offset to rate base, regardless of the seller's affiliation status with Mon Power and regardless of whether the seller was a FirstEnergy entity. If there was no affiliation status, Mon Power would not need to record ADIT in account 282 and would subsequently not need to record an offsetting amount in account 190. The end result to rate base is the same regardless of the seller's affiliation status with Mon Power. Simply put, there is no cash impact associated with the ADIT balance in the sales transaction, regardless of the seller's affiliation status with Mon Power.

Accordingly, the Commission should reject WVEUG's suggestion to utilize the ADIT credit of $33.12 million from the Pleasants transaction as an offset to the Transaction Surcharge rate base. The proper accounting treatment of the ADITs related to the Pleasants transaction results in both an ADIT credit and an ADIT debit on Mon Power's balance sheet, both in the amount of $33.12 million, with the effect of the ADIT transfer resulting in no net change in rate base used in the calculation of the Temporary Surcharge. This is in compliance with FERC's guidance on accounting for deferred income taxes on intercompany property transfers, Docket No. AI98-2-000.

ENEC Rates

Q. PLEASE SUMMARIZE WVCAG-SUN'S CLAIM THAT THE COMPANIES OVERSTATED THE 2018 PROPOSED RATE DECREASE.

A. WVCAG-SUN witness Schlissel claims that the average 2018 price used in the ENEC rate analysis was 6.4% higher than the average market price used by CRA in their dispatch modeling. Schlissel at 67.

Q. IS WVCAG-SUN CORRECT?

A. No. Witness Schlissel's claim is erroneous. For 2018, the Companies forecasted a price of $32.53 per megawatt-hour ("MWh") for energy generated by Pleasants and sold into the PJM market. The value used by CRA in its modeling for 2018 was $32.46 per MWh. This is a difference of 7 pennies, or 0.2%. Because the values used by the Companies and CRA were nearly identical for 2018, Mr. Schlissel's position is incorrect.

Q. WHY IS THE COMPANIES' 2018 FORECASTED ENERGY RATE REASONABLE?

A. As indicated in my direct testimony, the proposed ENEC rate reduction in 2018 was developed using the identical forecast used to develop the currently effective ENEC rates approved by the Commission in the 2016 ENEC filing[9] for rates effective January 1, 2017. In that ENEC filing, the review period had an ENEC under-recovery balance of $119.4 million, which was designed to be eliminated by the end of 2018 as a result of the combined effect of new ENEC rates during 2017-2108 along with the over-recovery that occurred during the third quarter of 2016. The energy market forecast in PJM during 2017-2018 is inherent in the design of ENEC rates effective during that same time period.

Internal modeling forecasted that the ENEC under-recovery balance would be $52.3 million as of the end of August 2017. Actual results have been better than forecasted. As of the end of August 2017, the ENEC under-recovery balance is about $33.7 million, not $52.3 million. This is nearly $19 million *better* than where the ENEC deferral balance was forecasted to be at the end of August 2017, and a nearly $86 million decrease as compared to the $119.4 million balance at the end of the prior ENEC review period. Since current ENEC rates are dependent upon forecasted PJM energy market rates, such a dramatic decrease in the ENEC under-recovery balance could not have been possible if the forecasted energy rates had been unreasonable.

[9] Case No. 16-1121-E-ENEC.

Q. PLEASE RESPOND TO MR. SCHLISSEL'S CRITICISM THAT THE COMPANIES DID NOT ESTIMATE THE IMPACT OF THE PLEASANTS TRANSACTION BEYOND 2018.

A. Rates will change in 2019 due to factors unrelated to the Pleasants transaction. For example, the ENEC deferred under-recovery balance of $119.4 million as of the last review period is projected to be eliminated by the end of 2018, which could certainly affect ENEC rates beginning in 2019, especially if the ENEC deferral transitions to an over-recovery. In addition, other factors will affect future rates regardless of the Pleasants transaction, including, but not limited to, the cost of fuel for Mon Power's existing generation assets and purchased power costs and revenues. These factors all play a part in developing future retail rates and will cloud the future incremental retail rate impact associated with the Pleasants transaction. As such, my direct testimony provided the retail rates and retail rate impact through 2018, which is the period by which existing rate schedule rates have been determined. Retail rate impacts beginning with 2019 incorporating the provisions previously described as well as the Pleasants transaction, if approved by the Commission, will be provided in accordance with the reconciliation procedure as described in my direct testimony.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY AT THIS TIME?

A. Yes, it does.